Exploring Clean Energy pathways

The role of CO_2 storage

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Abstract

Carbon capture, utilisation and storage will be an important part of the portfolio of technologies and measures needed to achieve climate and energy goals. In the International Energy Agency Clean Technology Scenario (CTS), a cumulative 107 gigatonnes of carbon dioxide (Gt CO_2) are permanently stored in the period to 2060, requiring a significant scale-up of CO_2 storage from today's levels. This report analyses the implications for the global energy system of CO_2 storage facilities not being developed at the scale and pace needed to follow the optimised pathway of the CTS. By limiting CO_2 storage availability to 10 Gt CO_2 over the scenario period, the analysis provides insights into the additional measures and technologies that would be required in the power, industrial, transport and buildings sectors in order to achieve the same emissions reductions by 2060 as the CTS.

The Limited CO_2 Storage scenario variant (LCS) finds that restricting the role of CO_2 storage would result in higher costs and significantly higher electricity demand, with 3 325 gigawatts of additional new generation capacity required relative to the CTS (a 17% increase). The main reason is that limiting the availability of CO_2 storage would require much more widespread use of electrolytic hydrogen in industry and the production of synthetic hydrocarbon fuels. More generally, the LCS would increase reliance on technologies that are at an earlier stage of development. Beyond the scenario period of 2060, constraints on CO_2 storage availability would also limit the availability of many carbon dioxide removal options, and may therefore not be consistent with the achievement of long-term climate goals.

Highlights

- **Limiting the availability of CO_2 storage would increase the cost of the energy transition.** The emissions reduction pathway of the Clean Technology Scenario (CTS) assumes that CO_2 storage is widely available to meet globally-agreed climate goals. It requires an additional investment of USD 9.7 trillion in the power, industrial and fuel transformation sectors, relative to a scenario that includes only current national commitments. Limiting CO_2 storage results in an increase of these additional investments by 40%, to USD 13.7 trillion, relying on more expensive and nascent technologies.

- **Demand for decarbonised power would expand even further.** In the Limited CO_2 Storage scenario variant (LCS), electricity generation would increase by 13% in 2060, or 6 130 TWh, relative to the CTS. This would require additional low-carbon generation capacity of 3 325 GW in 2060, which is nearly half of the total installed global capacity in 2017. In locations where a rapid scale-up of wind and solar capacity are constrained due to land use or other factors, imported hydrogen may become an important alternative.

- **Alternative processes and novel technologies would be required in industry.** In the LCS, the production of iron and steel and chemicals would shift more strongly towards non-fossil-fuel-based routes. In 2060, 25% of liquid steel, around 5% of ammonia and 25% of methanol production would use electrolytic hydrogen. The marginal abatement cost to industry in 2060 would double to around USD 500/tCO_2, relative to the CTS. This would shift abatement efforts towards other sectors and increase industrial emissions by 4.8 Gt CO_2.

- **Cement production has limited alternatives to carbon capture, utilisation and storage (CCUS).** Two-thirds of emissions from cement production are process emissions and the lack of competitive alternatives to CCUS means that this sector would absorb almost half of the available CO_2 storage capacity in the LCS. The use of CO_2 storage in this sector would be around 15% (0.7 Gt CO_2) lower than in the CTS to 2060, and emissions would increase concomitantly.

- **Synthetic hydrocarbon fuels would become a more important emissions reduction strategy.** In the LCS, synthetic hydrocarbon fuels based on biogenic CO_2 would need to become viable as an alternative to bioenergy with carbon capture and storage. These fuels would require around 4 700 TWh of electricity, replacing 9% of global primary oil and 2% of natural gas demand. Electrolyser capacity additions would average 40 GW per year from today to 2060 in the LCS, which is much higher than the 0.015 GW of new capacity installed in 2018.

- **Carbon capture would retain a role, with increased use of CO_2 in industry and fuel transformation.** CO_2 use would grow by 77% in the LCS relative to the CTS, but remain relatively small. In the LCS, 13.7 Gt CO_2 would be used to 2060 for the production of synthetic fuels, methanol and urea, with close to one-third of the CO_2 used from biogenic sources.

- **A dual challenge would emerge for a net zero emissions energy system.** Limited availability of CO_2 storage would increase the challenge of direct abatement in key sectors and, in parallel, constrain the possibility for carbon dioxide removal or "negative emission" technologies. In a carbon-neutral energy system, these technologies can compensate for residual emissions that are difficult to abate directly.

Executive summary

Carbon capture, storage and utilisation play a critical role in achieving climate goals

Carbon capture, utilisation and storage (CCUS) technologies offer an important opportunity to achieve deep carbon dioxide (CO_2) emissions reductions in key industrial processes and in the use of fossil fuels in the power sector. CCUS can also enable new clean energy pathways, including low-carbon hydrogen production, while providing a foundation for many carbon dioxide removal (CDR) technologies.

In the Clean Technology Scenario (CTS), the central decarbonisation scenario in this analysis, CCUS deployment reaches 115 gigatonnes of CO_2 (Gt CO_2) by 2060, with 93% of the captured CO_2 permanently stored. The level of deployment in the CTS would require a substantial and rapid scale-up of CCUS from today's levels, with 18 large-scale projects currently capturing around 33 million tonnes of CO_2 (Mt CO_2) each year.

Limiting the availability of CO_2 storage would increase the cost and complexity of the energy transition

CO_2 storage is a critical component of the CCUS opportunity. To better understand the value of CCUS as part of a portfolio of climate mitigation technologies, a variant of the CTS was developed that limits CO_2 storage availability to 10 Gt CO_2 in the period to 2060 – the Limited CO_2 Storage scenario variant (LCS). This increases the cost and complexity of achieving the same emissions reductions as the CTS, particularly for key industrial sectors such as cement production. At USD 13.7 trillion (United States dollars), the additional investment needs of the power, fuel transformation and industrial sectors in the LCS would be 40% (USD 4 trillion) higher than the additional investments needed to achieve the CTS, relative to the baseline Reference Technology Scenario (RTS).

Limiting the availability of CO_2 storage would result in the marginal abatement costs for the industrial sector doubling in 2060 relative to the CTS, from around USD 250 per tonne of CO_2 (tCO_2) to USD 500/tCO_2, due to reliance on more expensive and novel technology options. In the power sector, the marginal abatement costs in 2060 would increase from around USD 250/tCO_2 in the CTS to USD 450/tCO_2.

The effects would be felt across the energy system

The higher marginal abatement costs in the sectors directly reliant on CCUS would result in a shift of mitigation activity across the energy system. In the LCS, the cumulative CO_2 emissions from the fuel transformation sector would increase by 55% (17 Gt CO_2) relative to the CTS, in industry by 2% (4.8 Gt CO_2) and in the power sector by 2% (5.7 Gt CO_2). This would require additional efforts to reduce emissions in the buildings and transport sectors, with emissions 15% and 6% lower respectively, relative to the CTS.

In the buildings sector, these efforts would include a further acceleration of the phase-down of fossil-based heating technologies. Aggressive deployment of very high-efficiency technologies (light-emitting diodes, heat pumps and air conditioners) would need to start immediately and scale-up faster than in the CTS. In the transport sector, behaviour changes and a major policy push would be needed for a 8% increase in rail activity and a 16% increase in bus activity in 2060 (in vehicle kilometres travelled) relative to the CTS, alongside increased electrification and reduced activity from smaller passenger light-duty vehicles. Freight truck activity would also be 9% lower in 2060.

Limiting CO_2 storage would drive new power demand

Even with strong efficiency measures, significant new investment would be required in the power sector in the LCS, with an additional 6 130 terawatt hours (TWh) of electricity generated in 2060 relative to the CTS (a 13% increase). This would require additional generation capacity of 3 325 gigawatts (GW), which is nearly half of the installed global capacity in 2017. Almost all of this additional capacity would be wind and solar photovoltaics (PV), with 25% higher capacity in 2060 in the LCS. Such a rapid and widespread scale-up of these technologies may have implications for land use, permitting, and infrastructure development in some regions. For example, approximately 173 000 additional onshore wind turbines would be required (assuming an average size of 5 MW) in the LCS compared with the CTS. Where domestic renewable capacity is constrained, importing hydrogen-based fuels may be a viable alternative.

Most of the increase in power demand in the LCS would be driven by the industrial and fuel transformation sectors, in particular due to greater reliance on electrolytic hydrogen. In 2060 in the LCS, around 9% of global electricity generation would be used for the production of synthetic hydrocarbon fuels, supported by dedicated, off-grid renewable electricity generation. This would require a massive scale-up in the production of hydrogen and the related infrastructure for hydrogen transport or further conversion in synthetic hydrocarbon fuels or ammonia.

Limiting availability of CO_2 storage means that power generation with CO_2 capture would almost vanish in the LCS relative to the CTS, which has around 615 GW of CCUS capacity attached to coal, gas and biomass facilities in 2060. Coal-fired power plants would be phased out more rapidly in the LCS, at an average of 60 GW of capacity per year in the period 2025–40 compared with an average of 45 GW per year in the CTS. The earlier retirements would result in lost revenue of around USD 1.8 trillion between 2017 and 2060.

Major technology shifts would be needed in industry

In the LCS, the production of iron and steel and chemicals would shift more significantly towards non-fossil fuel-based routes and more novel technology options. In 2060, 25% of liquid steel, around 5% of ammonia and 25% of methanol production would rely on electrolytic hydrogen. In the case of steel, this process is yet to be tested at scale, although pilot trials are planned.

Two-thirds of emissions from cement production are process emissions, and the lack of competitive alternatives to CCUS would see this sector absorb almost half of the available CO_2 storage capacity in the LCS. Relative to the CTS, the use of CO_2 storage in this sector would be reduced by around 15% (0.7 Gt CO_2) in the period to 2060, and the emissions from the cement sector would increase concomitantly (a 1% cumulative increase in cement emissions).

Synthetic hydrocarbon fuels would make inroads

CCUS is a lower-cost emissions reduction option in the fuel transformation sector and contributes almost half of the emissions reductions achieved in the sector in the CTS. This includes supporting the sector to become net carbon negative by 2060 through the deployment of bioenergy with carbon capture and storage (BECCS). With limited CO_2 storage, synthetic hydrocarbon fuels based on biogenic CO_2 would be required at greater scale as an alternative to BECCS. In the LCS, these fuels would require around 4 700 TWh of electricity and replace 9% of global fossil primary oil demand and 2% of natural gas demand.

Achieving net zero emissions would become more challenging

Limiting the availability of CO_2 storage would increase the challenge of direct abatement in key sectors, such as cement production, and in parallel would constrain the deployment of CDR or "negative emission" technologies. In a carbon-neutral energy system, these technologies are needed to compensate for residual emissions that are difficult or too expensive to abate directly. In many pathways that limit future temperatures to 1.5°C, global emissions become net negative in the second half of the century and this will rely on significant deployment of CDR technologies and CO_2 storage. An ongoing constraint on CO_2 storage beyond 2060 is therefore unlikely to be consistent with long-term climate goals.

Findings and recommendations

Policy recommendations

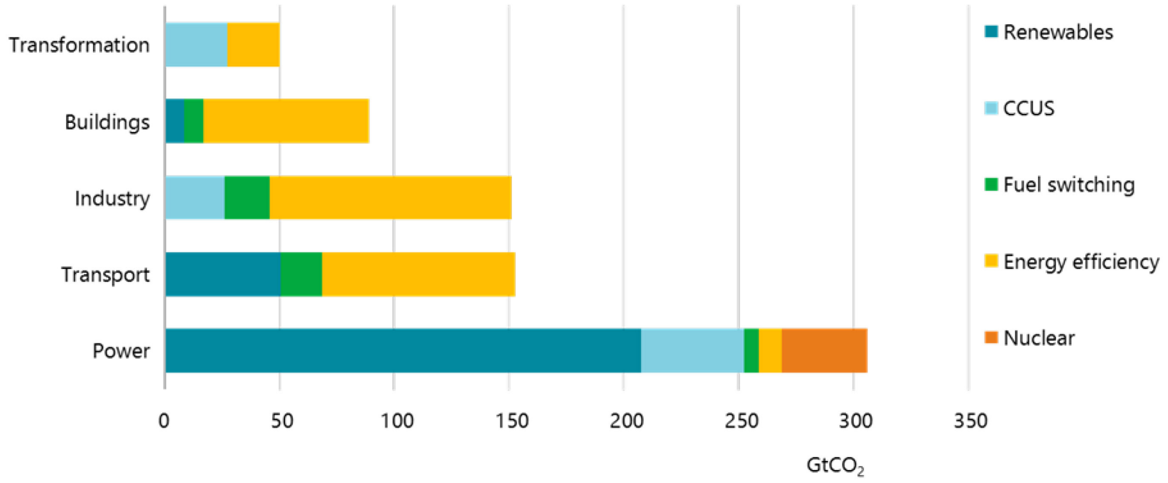
- Support the development and deployment of carbon capture, utilisation and storage (CCUS) as part of a least-cost portfolio of technologies needed to achieve climate and energy goals.
- Accelerate pre-competitive exploration and assessment of CO_2 storage facilities in key regions to ensure future availability of storage.
- Establish policy and regulatory frameworks for CO_2 storage that provide certainty and transparency for investors and the broader community.
- Facilitate planning and investment for multi-user CO_2 transport and storage infrastructure capable of servicing a range of industrial and power facilities.
- Support research, development and demonstration to improve the performance and cost-competitiveness of technologies that may be important where CO_2 storage availability is limited, including CO_2 use, electrolytic hydrogen and synthetic hydro-carbon fuels produced from hydrogen.

CCUS technologies play a critical role in achieving climate goals

Achieving climate goals will require a transformation of global energy systems of unprecedented scope, speed and ambition. CCUS technologies are expected to play a critical role in supporting this transformation as part of a least-cost portfolio of technologies and measures (Figure 1). CCUS offers a solution for deep emissions reductions from key industrial processes, including the production of iron and steel, cement and chemicals, which remain the building blocks of modern societies. In the power sector, CCUS can provide greater diversity in generation options and address the potential for "lock-in" of emissions from existing infrastructure. CCUS can also enable new clean energy pathways, including low-carbon hydrogen production from fossil fuels for heating, transport and power generation. Virtually all hydrogen production today is from fossil fuels, primarily natural gas, and around 1 800 MW of production is equipped with CCUS (IEA, 2019). Critically, CCUS also provides the infrastructure and knowhow to accelerate the deployment of CO_2 removal technologies, such as bioenergy with carbon capture and storage (BECCS) and direct air capture.

In the Clean Technology Scenario (CTS), CCUS technologies contribute 13% of the cumulative emissions reductions needed to 2060, relative to the baseline Reference Technology Scenario. This makes CCUS the third-largest contribution, behind energy efficiency (39%) and renewables (36%). Nuclear and fuel switching account for 5% and 7% respectively.

Figure 1. Global CO_2 emissions reductions by technology area and sector, RTS to CTS



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

In the CTS, CCUS delivers 13% of the cumulative emissions reductions to 2060.

Between 2018 and 2060, a total of 115 gigatonnes of CO_2 (Gt CO_2) are captured from the power sector (49% of the total CO_2 captured), industrial processes (25%) and upstream transformation and processing (27%). Of the captured CO_2, 35 Gt (30%) are from the processing and combustion of biomass, creating negative emissions that offset emissions in other sectors that are more difficult or costly to abate directly. In the CTS, 93% of the captured CO_2 is permanently stored in geological formations and the remainder (7.9 Gt CO_2) is used in processes such as methanol production.

The implications of limiting CO_2 storage would be felt across all sectors

The deployment of CCUS in the CTS would require a rapid scale-up from today's levels, with only around 33 million tonnes of CO_2 (Mt CO_2) currently captured each year for storage or use in enhanced oil recovery (CO_2-EOR). While there is a high degree of confidence that global CO_2 storage resources are well in excess of future requirements, including those modelled in the CTS, failure to assess and develop these resources in a timely manner could act as a brake on CCUS deployment.

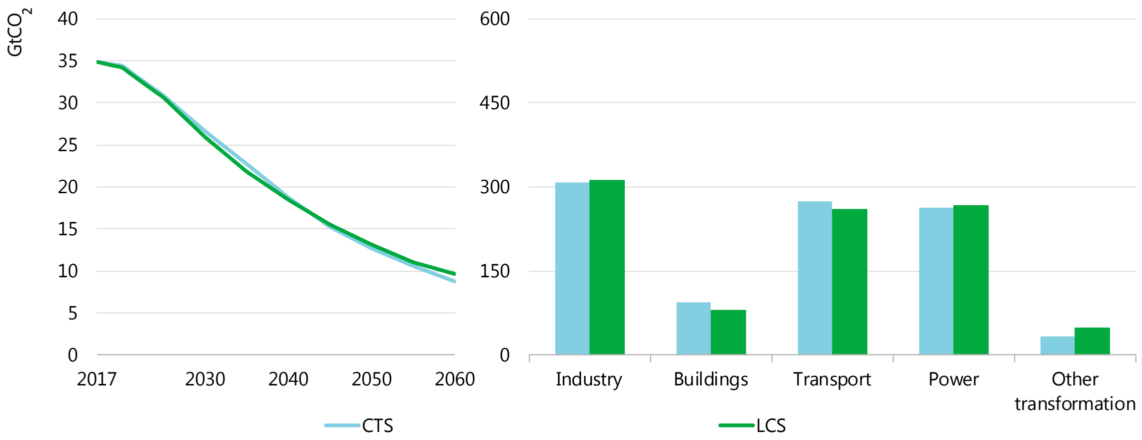
The Limited CO_2 Storage scenario variant (LCS) considers the implications for the global energy system if the required investment in CO_2 storage is not undertaken. In the LCS, CO_2 storage availability is limited to 10 Gt CO_2 over the scenario period, equivalent to the level of CO_2 storage developed in the Reference Technology Scenario (RTS), which considers only existing commitments and trends. The LCS is designed to achieve the same level of emissions reductions as the CTS, so as to explore the implications of limiting the availability of CO_2 storage on energy sector as a whole (Figure 2). Nonetheless, the LCS would still deliver a 15-fold increase in annual CO_2 storage rates from today's levels.

With limited availability of storage, the cumulative CO_2 emissions from the sectors reliant on CCUS would increase relative to the CTS, by 55% (17 Gt CO_2) in fuel transformation, 2% in industry (4.8 Gt CO_2) and 2% (5.7 Gt CO_2) in the power sector. This would require additional efforts to reduce emissions in the buildings and transport sectors, by 15% and 6% respectively, relative to the CTS.

In the buildings sector, the limited availability of CO_2 storage would require an even more accelerated phase-down of fossil-based heating technologies than in the CTS, with a strategic shift to more efficient electricity-driven technologies, district energy and renewables (solar thermal and modern solid biomass). The market share of coal- and oil-fired heating equipment would drop to only 5% in 2030 globally, and the combined sales share of coal-, oil- and gas-fired technologies in 2060 would be further reduced by nearly half. Over the 2018-60 period, fossil fuel-related emissions would be reduced by 15% relative to the CTS. In parallel, the deployment of very high-efficiency technologies (light-emitting diodes, heat pumps and air conditioners) would need to be start immediately, even more quickly than in the CTS. Additional energy efficiency measures in the buildings sector would generate close to 1 700 terawatt hours (TWh) of electricity savings annually by 2060 and reduce overall power demand in the sector by nearly 10% compared with the CTS.

In the transport sector, behavioural changes and a major policy push would be needed to support greater electrification of road modes and to shift passenger transport to buses and rail. The share of electric passenger light-duty vehicles (PLDVs) in the total fleet would increase from 62% in 2060 in the CTS to 70% in the LCS, from less than 1% today, while PLDV activity would (measured in vehicle kilometre miles [vkm]) decline by a further 2% in the LCS relative to the CTS. Passenger rail activity (in vkm) would increase by 8% in 2060 relative to the CTS and bus activity by 16%, with a range of measures required to support this shift to public transport, including fiscal incentives, regulations and additional investment in public transport networks. Freight truck activity would also be 9% lower in 2060.

Figure 2. Global CO_2 emissions by scenario and cumulative emissions to 2060 by sector and scenario



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

In the LCS, additional efforts would be required in the buildings and transport sectors to compensate for higher emissions from industry, power and fuel transformation.

The cost of the transition would increase

Achieving the ambitious emissions reductions of the CTS would require an additional USD 9.7 trillion (United States dollars) in investment in power generation, transformation and industry, above that of the RTS. To achieve the same CO_2 emissions with limited availability of CO_2 storage, this additional investment would need to increase by 40%, to USD 13.7 trillion.

Most of the additional investment in the LCS relative to the CTS would be in power generation, with an additional USD 3.1 trillion needed to accommodate the increased electricity demand from the industrial sector and for the production of synthetic hydrocarbon fuels from electrolytic hydrogen. An additional USD 0.9 trillion in investment would flow directly into the industrial and fuel transformation sectors. These investment figures do not account for the economic losses associated with early retirement of existing assets, including an estimated additional USD 1.8 trillion in lost revenue (on an undiscounted basis) from coal-fired power generation retirement in the LCS compared with the CTS.

With limited availability of CO_2 storage, the marginal CO_2 abatement cost in the power, industrial and fuel transformation sectors would increase significantly compared with the CTS. By 2060, the marginal abatement cost in the power sector and in fuel transformation would approach USD 450/tCO_2, compared with USD 250/tCO_2 in the CTS. For industry, the marginal abatement cost would double to around USD 500/tCO_2 in 2060 compared with USD 250/tCO_2 in the CTS. The higher marginal abatement costs in industry and fuel transformation would shift mitigation efforts to other parts of the energy system.

Demand for decarbonised power would grow

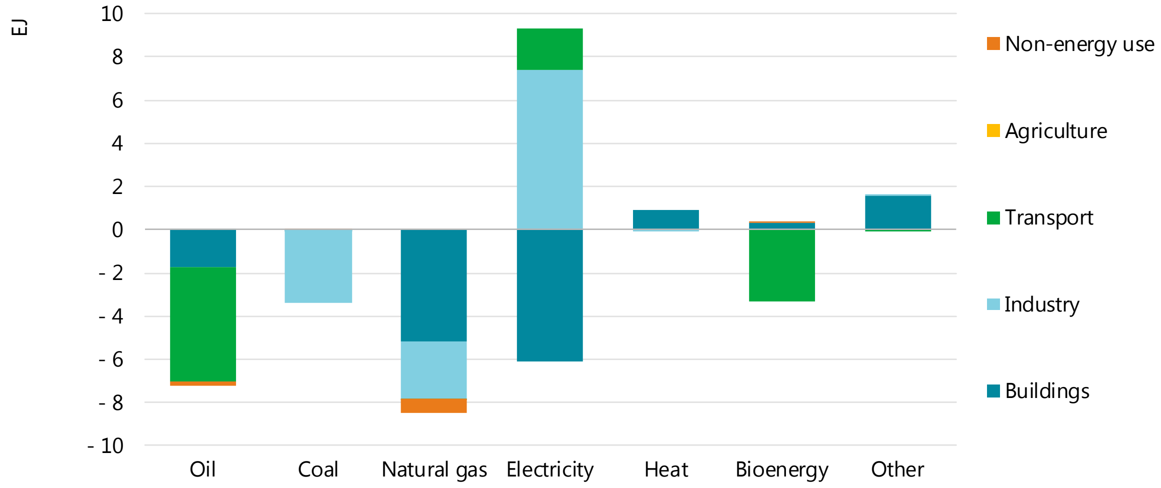
The CTS involves a major shift towards electrification of end-use sectors that would need to be pushed even further if the availability of CO_2 storage were limited. In the CTS, electricity becomes the largest end-use fuel, reaching a share of 36% (from 18% today) with absolute electricity consumption nearly doubling between 2017 and 2060. In parallel, global power generation is virtually decarbonised, with the average CO_2 intensity falling from 530 grams of carbon dioxide per kilowatt hour (g CO2/kWh) in 2017 to 4 g CO2/kW in 2060.

In the LCS, electricity generation in 2060 would be 13% or 6 130 TWh higher than the CTS, equivalent to approximately twice the electricity generated in the European Union in 2017 (Figure 3). The increased demand for electricity would be led by industry and fuel transformation, in particular for electrolytic hydrogen. This increase in demand would be larger if not for higher costs for residential and commercial customers in the LCS, which would trigger additional efficiency measures and a 9% reduction in electricity demand from the buildings sector.

The LCS would require the installation of 3 325 gigawatts (GW) of additional generation capacity, primarily solar and wind (Figure 4), which is nearly half of total global generation capacity in 2017. In particular, an additional 1 966 GW of solar would be installed over and above the 7 600 GW installed in the CTS in 2060, from a level of around 400 GW today. This expansion may have implications for land use and infrastructure development, with a 100-MW solar installation requiring around 100 hectares of land. Further, an additional 864 GW of onshore wind capacity would be built in the LCS, implying approximately 173 000 additional wind turbines (assuming an average size of 5 MW).

Without the option of CCUS, coal-fired generation would need to be phased out more rapidly, with an average of 60 GW of early retirements each year between 2025 and 2040 in the LCS, compared with an average of 45 GW in the CTS for the same period.

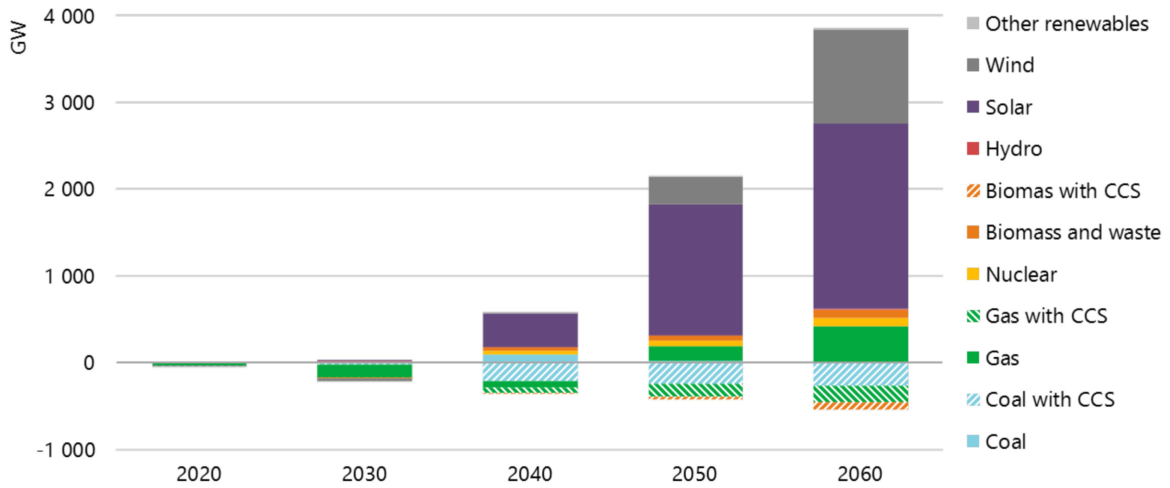
Figure 3. Global final energy demand changes in the LCS relative to the CTS, 2060



Notes: EJ = exajoule. Analysis above uses the Energy Technology Perspectives modelling framework.

With limited CO_2 storage, electrification would become even more important to reduce emissions in industry and transport.

Figure 4. Changes in global installed power generation capacity by fuel in the LCS relative to the CTS



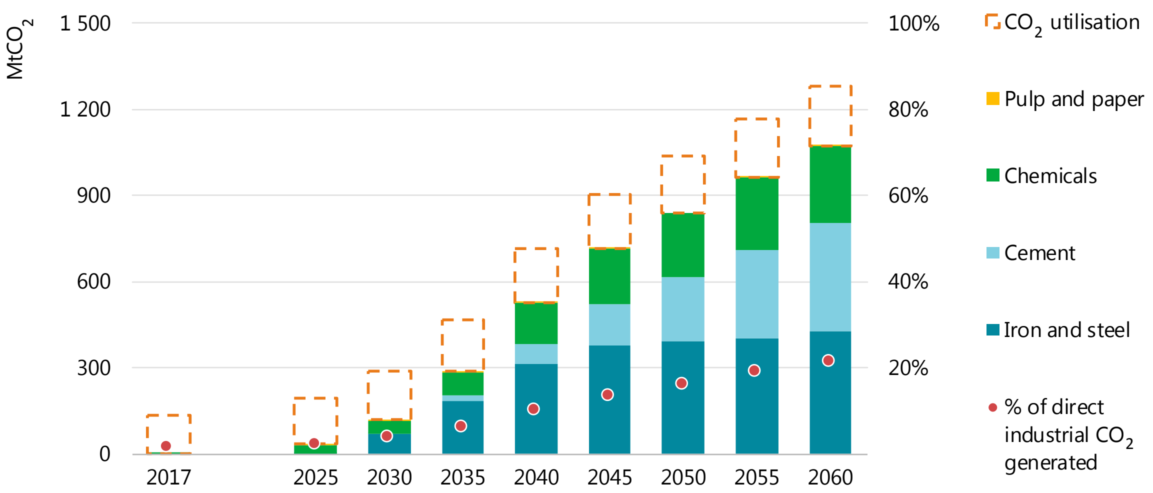
Note: Analysis above uses the Energy Technology Perspectives modelling framework.

Solar and wind would account for much of the additional generation capacity needed with limited availability of CO_2 storage.

Major technology shifts would be needed in industry

CCUS plays an important role in industry in the CTS (Figure 5), particularly as a solution for process-related emissions, delivering around 15% of the cumulative emissions reductions needed to 2060. Limiting the deployment of CO_2 storage would require greater deployment of alternative emission reduction strategies and technologies, many of which are at a very early stage of development today. With best available technologies widely deployed and cost-effective process integration improvements pursued significantly in the CTS, the focus in the LCS would shift towards material efficiency and new renewables-based processes, including those that rely on low-carbon electricity such as electrolytic hydrogen.

Figure 5. Captured CO_2 for storage by industrial sub-sector and for utilisation in the CTS



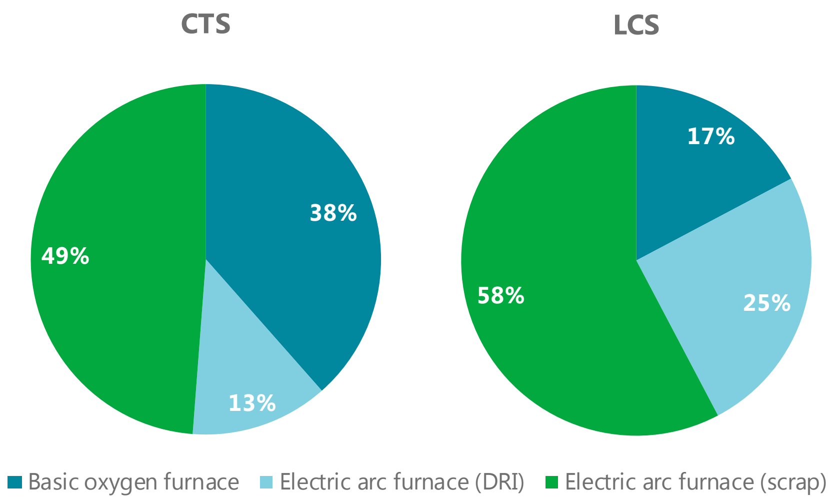
Notes: CO_2 utilisation refers to its application for the production of urea and methanol. Analysis above uses the Energy Technology Perspectives modelling framework.

Around 20% of direct industrial CO_2 emissions generated are captured either for storage or use in 2060 in the CTS.

In the **iron and steel sector**, up to 10 Gt CO_2 is captured and stored cumulatively in the CTS, with around 44% of the sector's emissions captured in 2060. In the LCS, material efficiency and scrap-based electric arc furnace production would be increased relative to the CTS and more innovative processes would be deployed, particularly hydrogen-based direct reduced iron (DRI) (Figure 6). Hydrogen-based DRI would dominate the DRI production route by 2060 and contribute to the sector's demand for electricity increasing by 2.5 times relative to the CTS in 2060. This process is yet to be tested at scale, with pilot trials planned to commence in 2021. As such, the deployment in the LCS would be limited in the period to 2040, but significantly increased thereafter.

In the **cement** sector, around 5 Gt CO_2 is captured and stored cumulatively to 2060 in the CTS, with around 20% of the sector's emissions captured in 2060. Two-thirds of the emissions from the cement sector are process emissions, attributable to the decomposition of limestone (calcium carbonate) when producing clinker, the main substance found in cement. In the LCS, advances to reduce the clinker-to-cement ratio and material efficiency strategies would become more important, but the lack of alternatives to CO_2 storage for direct emissions means that reliance on CCUS would be reduced by only 15% relative to the CTS. Around 4 Gt CO_2 would be captured in the LCS, with the cement sector absorbing almost half of the limited CO_2 storage allocation in the period to 2060.

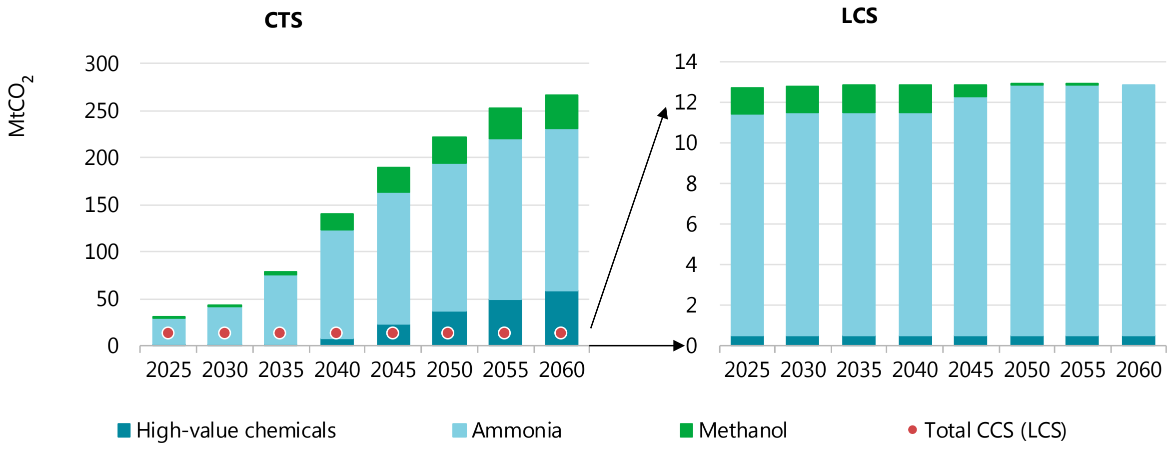
Figure 6. Liquid steel production by process route and scenario in 2060



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

In the LCS, DRI- and scrap-based routes would increase at the expense of primary production using a basic oxygen furnace.

Figure 7. Captured CO_2 for storage in the chemicals sector by scenario



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

When limiting CO_2 storage, most of the capture applications in the chemical sector would be concentrated in ammonia production.

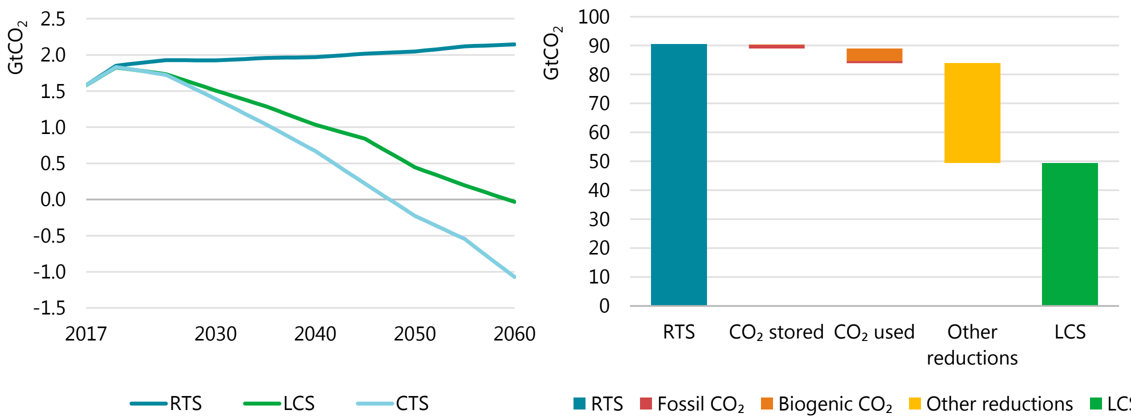
In the **chemicals** sector, 6 Gt CO_2 is captured and stored cumulatively in the CTS, with around 25% of the sector's annual emissions captured and stored in 2060. CCUS is a cost-effective emissions reduction strategy in chemicals, particularly in processes where the CO_2 is already inherently separated and/or where concentrated CO_2 streams are produced, such as ammonia production. Limiting CO_2 storage availability result in a combined increase of 2.5 times in ammonia and methanol production using electrolysis by 2060, relative to the CTS. As a result, the electricity demand for these two chemicals would nearly double in 2060 relative to the CTS. The increase in methanol production based on electrolytic hydrogen would also result in a fivefold increase in CO_2 use relative to the CTS, to 60 Mt CO_2 in 2060. In the LCS, CO_2 storage for the chemicals sector would be reduced by 90% and, of this, around 90% of the stored CO_2 would be captured from ammonia production (Figure 7).

Synthetic hydrocarbon fuels would make inroads

CCUS contributes approximately half of the emissions reductions achieved in the CTS in the fuel transformation sector, which includes energy use for oil and gas production and refining. In the CTS, 31 Gt CO_2 of the sector's emissions are permanently stored and the uptake of BECCS sees emissions from fuel transformation become net negative by 2060.

With limited CO_2 storage, the option of using captured CO_2 in combination with electrolytic hydrogen would become more important for the production of synthetic liquid or gaseous hydrocarbon fuels (power-to-liquids [PtL] and power-to-gas [PtG]). These synthetic fuels can substitute for fossil fuels and, where the CO2 used is sourced from bioenergy, they can support similar emissions reductions, such as applying BECCS to offset the equivalent use of fossil fuels. Hence, while the cumulative emissions from the fuel transformation sector would be 17 Gt CO_2 higher in the LCS relative to the CTS, the net emissions from the sector would still become marginally negative by 2060 (Figure 8).

Figure 8. Annual CO_2 emissions from fuel transformation and cumulative CO_2 reductions in the LCS



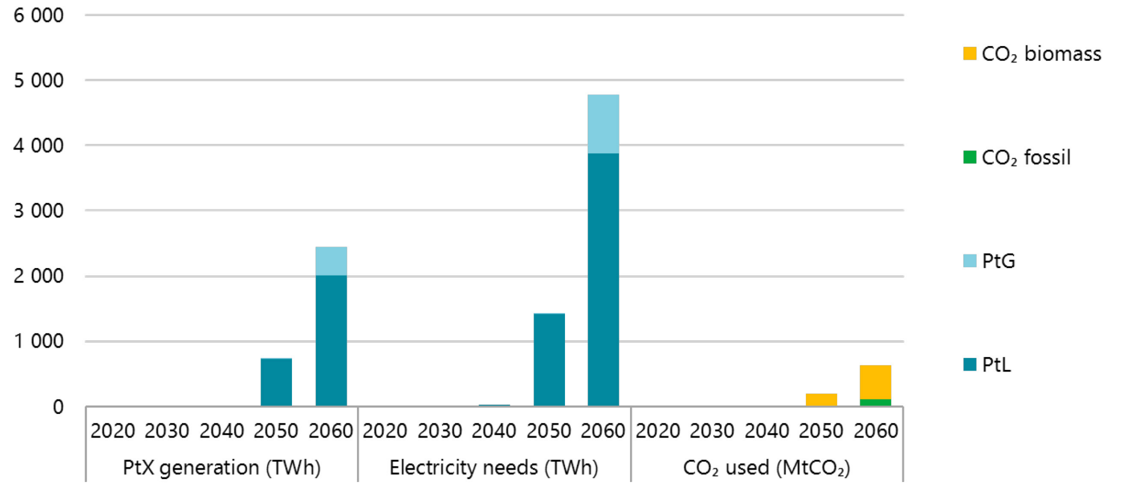
Note: Analysis above uses the Energy Technology Perspectives modelling framework.

CCUS would account for a sixth of the cumulative CO_2 emissions reductions in the fuel transformation sector in the LCS, largely from CO_2 use.

In the LCS, 4.4 Gt CO_2 of emissions from fuel transformation would be stored in the period to 2060 and 3.1 Gt CO_2 would be used, with 50% of this from biogenic sources. The reliance on synthetic hydrocarbon fuels from electrolytic hydrogen would be associated with a very large increase in electricity demand, with an additional 4 700 TWh of electricity required in 2060 to produce 2 400 TWh (8.5 EJ) of synthetic fuels (Figure 9). The additional power need for these synthetic fuels in 2060 is equivalent to almost 20% of global electricity demand in 2017, or more than the total electricity generated in the United States in 2017.

The LCS requires a rapid and sustained scale-up of electrolyser capacity, reaching 1 750 GW (at 2 700 full load hours) in 2060 or an average of 40 GW per year over the next four decades. By means of comparison, in 2018, 0.015 GW of electrolyser capacity was added for energy purposes (IEA, 2019).

Figure 9. Fuel production, electricity demand and CO_2 use in the LCS



Notes: PtX = power-to-X, which includes PtG and PtL. Analysis above uses the Energy Technology Perspectives modelling framework.

CO_2 use options in the LCS would produce 2 400 TWh (8.5 EJ) of synthetic fuels in 2060, which would require 4 700 TWh of electricity generation and 620 Mt CO_2.

Carbon capture would retain a role with increased CO_2 use

In the LCS, almost 24 Gt CO_2 would be captured from industry, fuel transformation and power generation for storage and use in the period to 2060, representing around 20% of the cumulative CO_2 capture rate in the CTS. CO_2 use would grow by 77% in the LCS relative to the CTS, with 13.7 Gt CO_2 used cumulatively for the production of methanol, urea and synthetic hydrocarbon fuels. The use of CO_2 in the LCS would be less than 13% of the CO_2 stored in the CTS.

References

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Technical analysis

1. Introduction

Achieving climate goals will require global energy systems to undergo a transformation of unprecedented scope, speed and ambition. Carbon capture, utilisation and storage (CCUS) technologies[1] are expected to play a critical role in supporting this transformation as part of a least-cost portfolio of technologies and measures.

CCUS technologies offer a solution for deep emissions reductions from hard-to-abate industrial processes, including the production of iron and steel, cement and chemicals, which combined account for about 15% of global carbon dioxide (CO_2) emissions and just over 20% of global final energy demand. In the power sector, CCUS can facilitate greater diversity in generation options and protect substantial capital investment in existing infrastructure. CCUS can also enable new clean energy pathways, including low-carbon hydrogen production for heating, transport and power generation. Critically, CCUS provides the infrastructure and knowhow to accelerate the deployment of carbon dioxide removal (CDR) technologies, such as bioenergy with CCUS and direct air capture with CO_2 storage. The Intergovernmental Panel on Climate Change (IPCC) recently highlighted that several hundred gigatonnes (Gt) of CDR would be needed by the end of the century even if a broad range of climate actions are taken – rising to 1 000 Gt cumulatively if other levers are not used.[2]

This analysis aims to explore the technology and investment implications of a future where the contribution of CCUS to achieving climate goals is limited. The analysis achieves this by constraining the availability of CO_2 storage. While CO_2 storage resources are expected to be well in excess of that required globally, even under very ambitious climate scenarios, a lack of investment in developing these CO_2 storage resources could in practice act as a significant brake on CCUS deployment.

The report builds on past analysis undertaken through the Energy Technology Perspectives (ETP) series, which has focused on the role of energy technologies in achieving multiple societal objectives, including delivering cost-effective mitigation options for meeting global climate ambitions. Central to the analysis is the use of scenarios to assess the implications of different pathways in the development of the energy system to 2060. In the central climate mitigation

[1] For the purpose of this report, CCUS is used as an inclusive term and refers to the process of capturing CO_2 for use or for permanent storage, including applications that involve a combination of both use and storage (such as CO_2 use in enhanced oil recovery). For clarity, the terms carbon capture and storage (CCS) and carbon capture and utilisation (CCU) or CO_2 use will also be used when the discussion specifically relates to either storage or use.
[2] IPCC (2018), *Special Report: Global Warming of 1.5C°*, www.ipcc.ch/report/sr15/.

scenario, the Clean Technology Scenario (CTS), cumulative emissions of more than 115 gigatonnes of carbon dioxide (Gt CO_2) are captured for permanent storage (107 Gt CO_2) or use (7.8 Gt CO_2) across the power generation, industrial and fuel transformation sectors in the period to 2060. In the Limited CO_2 Storage scenario variant (LCS), the availability of CO_2 storage is assumed to be restricted to only 10 Gt CO_2 over the scenario period, which is the level of deployment in the Reference Technology Scenario (RTS). See Box 1 and Annex I for an overview of the scenarios and Annex II for information on the ETP modelling framework.

Box 1. Scenarios discussed in this analysis

The **Reference Technology Scenario (RTS)** accounts for current country commitments to limit emissions and improve energy efficiency, including nationally determined contributions pledged under the Paris Agreement. By factoring in these commitments and recent trends, this scenario represents a shift from a historical "business-as-usual" approach with no meaningful climate policy response. However, global emissions increase by 8% by 2060 above the 2017 level, which is a pathway far from sufficient to achieve the temperature goals of the Paris Agreement.

The **Clean Technology Scenario (CTS)** lays out an energy system pathway and a CO_2 emissions trajectory in which CO_2 emissions related to the energy sector are reduced by around three-quarters from today's levels by 2060. Among the decarbonisation scenarios projecting a median temperature rise in 2100 of around 1.7–1.8ºC in the IPCC database, the trajectory of energy- and process-related CO_2 emissions of the CTS is one of the most ambitious in the medium term and remains well within the range of these scenarios through to 2060. The CTS is the central climate mitigation scenario used in this analysis. It represents an ambitious and challenging transformation of the global energy sector that relies on substantially strengthened efforts compared with today. It opens the possibility of the pursuit of ambitious global temperature goals, depending on action taken outside the energy sector and the pace of further emissions reduction after 2060.

The **Limited CO_2 Storage** scenario variant **(LCS)** assesses the energy system-wide implications of a possible failure or delay in making CO_2 storage available to the energy sector at the scale of the CTS. Although estimated global CO_2 storage capacity is considered to be more than adequate to meet future requirements, even under very ambitious climate scenarios, there remains a need to invest in the assessment and characterisation of specific sites. The LCS variant considers the system-level implications if this investment is not undertaken or if other factors impact CO_2 storage availability. The scenario variant is designed to achieve the same CO_2 emissions outcome as the CTS, but must rely on the deployment of other mitigation options to make up for the reduced CO_2 storage availability.

These scenarios should not be considered as predictions, but as analyses of the impact and trade-offs of different technology choices and policy targets, thereby providing a quantitative approach to support decision-making in the energy sector.

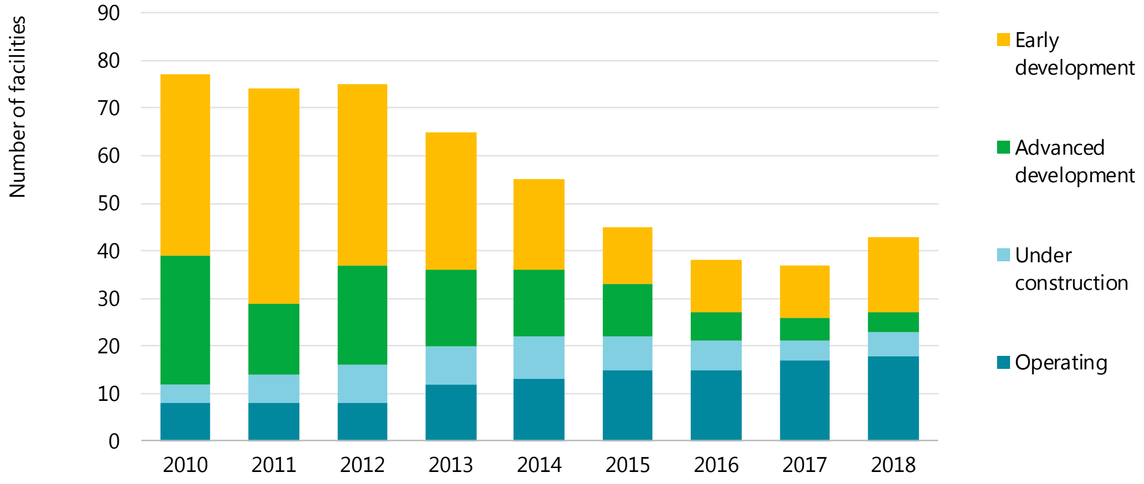
2. The role of CCUS in clean energy pathways

CCUS deployment today

Many applications of CCUS are not new or untested and global experience with industrial-scale CCUS facilities is growing. The capture and separation of CO_2 has been applied in industry for many decades and is an inherent part of some industrial processes, while the practice of injecting CO_2 for enhanced oil recovery (CO_2-EOR) first commenced in the 1970s. Today, there are 18 large-scale, integrated projects operating across various applications globally, including coal-fired power generation, natural gas processing, steel manufacture, fertiliser production and oil sands upgrading. Collectively, these projects are capturing around 33 million tonnes (Mt) of CO_2 each year.

Around two-thirds, or 12, of the operating CCUS projects are located in Canada and the United States, with all but one of these projects benefiting from a revenue stream for the captured CO_2 for use in EOR. For some early projects, the revenue from CO_2-EOR was sufficient for commercial CCUS operation, while more recently EOR revenue combined with capital grants has helped to close the commercial gap and support investment. CO_2-EOR opportunities are expected to remain a major factor for early CCUS deployment, with growing global interest, including in the Middle East and China.

Figure 10. Investment pipeline for large-scale CCUS projects



Source: IEA analysis based on Global CCS Institute (2019), *Facilities Database*, https://co2re.co/FacilityData.

The pipeline of large-scale CCUS projects has been shrinking since 2010, but is showing signs of recovery.

Beyond CO_2-EOR, the business case for investment in CCUS facilities is limited in the absence of a strong climate response and targeted policy support. In the past decade, policy support for CCUS has fluctuated and the level of public funding flowing to large-scale CCUS facilities since 2010 is less than 3% of the annual subsidies provided to renewable energy technologies (IEA, 2018a). This limited support has impacted CCUS investment and contributed to the cancellation of several planned projects, with a steady decline in the project pipeline between 2010 and 2017 (Figure 10).

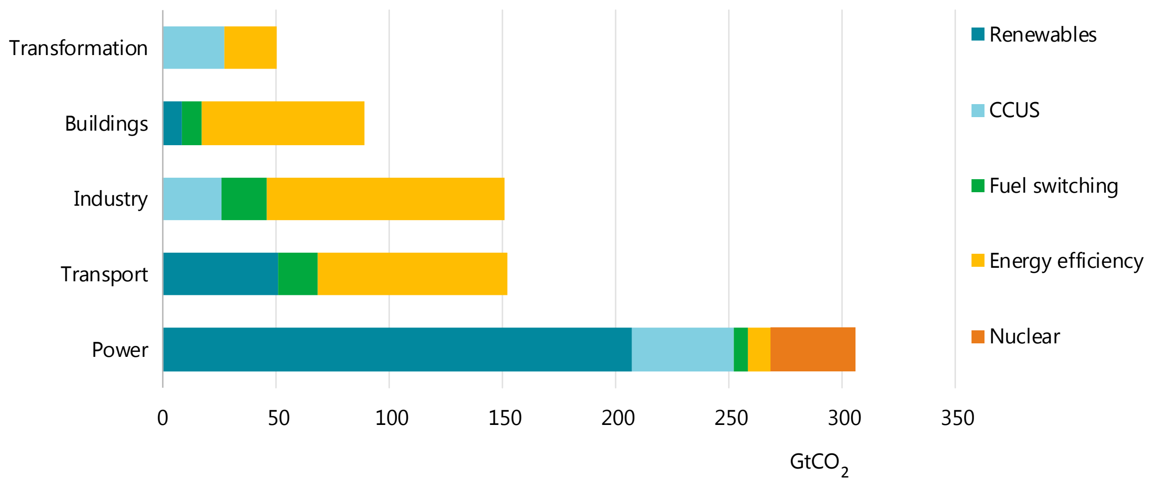
There are encouraging signs that the policy and investment environment for CCUS technologies is improving. For example, the introduction of "45Q" tax credits in the United States, which provide up to USD 50 (United States dollars) per tonne of CO_2 permanently stored or USD 35 per tonne of CO_2 used in EOR, is expected to trigger significant new CCUS investments. Many countries including Canada, China, Japan, the Netherlands, Norway, Saudi Arabia and the United Kingdom are also pursuing CCUS deployment at scale.

The Clean Technology Scenario and CCUS

The CTS sets out an ambitious emissions reduction pathway for the global energy sector, with an estimated additional cumulative abatement to 2060 over and above the RTS of 750 Gt CO_2, equivalent to more than 20 years of today's emissions. The growth of energy sector emissions is halted in the next few years and emissions decline sharply to reach 8.7 Gt CO_2 by 2060, 75% below 2017 levels.

A comprehensive portfolio of clean energy technologies is needed to deliver these emissions reductions (Figure 11). CCUS technologies contribute 13% of these cumulative emissions reductions across the power, industrial and fuel transformation sectors, the third-largest contribution behind energy efficiency (39%) and renewables (36%). Nuclear and fuel switching account for 5% and 7% respectively.

Figure 11. Global CO_2 emissions reductions by technology area: RTS to CTS



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

Energy efficiency, renewables and CCUS are central to reducing energy related emissions.

Between 2018 and 2060, 115 Gt CO_2 are captured in total across all sectors. The largest source of captured CO_2 is the power sector, from which 56 Gt CO_2 are captured over the scenario, while 28 Gt CO_2 are captured from industry and 31 Gt CO_2 from upstream transformation and processing. With CO_2 storage being widely available for development in the CTS, 93% (107 Gt) of captured CO_2 is stored, and only 7.8 Gt CO_2 (the remaining 7%) is used over the period. The CO_2 use is essentially an extension of processes that are already using CO_2, such as methanol and urea production, rather than widespread use of CO_2 in novel ways.

In the CTS, 35 Gt CO_2 is captured and stored from the processing and combustion of biomass in the period to 2060. This results in atmospheric CO_2 being sequestered, creating negative emissions vital for offsetting remaining emissions in other parts of the energy system. Bioenergy with carbon capture and utilisation (BECCU) or with carbon capture and storage (BECCS) are considered the most mature and scalable of CDR technology options and can offer a cost-competitive emissions reduction solution in industry and fuel transformation. In particular, the production of biodiesel or bioethanol is a relatively low-cost CO_2 capture opportunity due to the high concentration of CO_2 in the off-gas streams. Other CDR technology measures, such as direct air carbon capture and storage (DACCS), are at an earlier stage of development, but have potential to deliver large-scale negative emissions where the captured CO_2 is permanently stored.

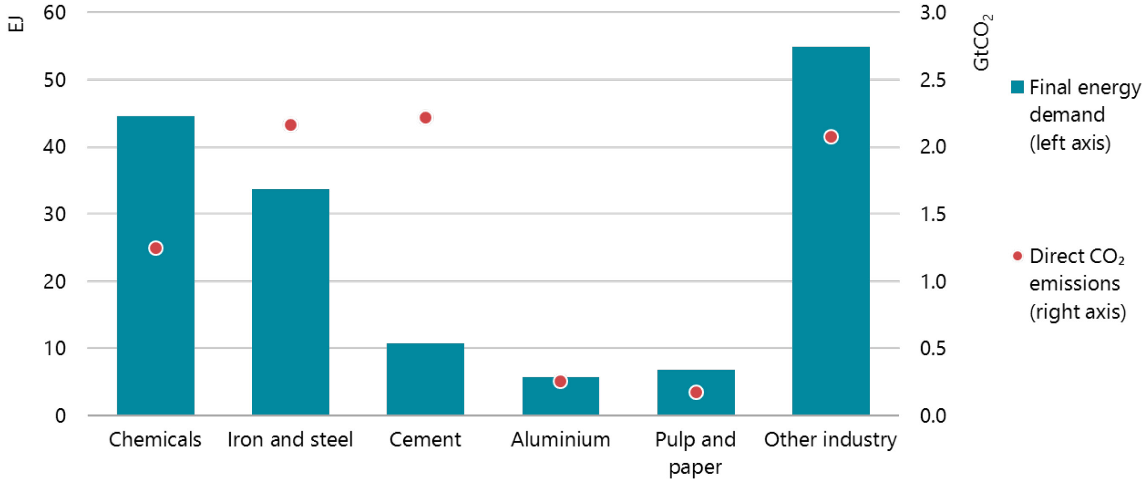
The role of CCUS in the industrial sector

The industrial sector includes a wide range of manufacturing activities, from the production of bulk materials such as crude steel or cement to the fabrication of electronic devices and food products. Industry overall accounts for 156 exajoules (EJ) (about 40% of total final energy demand) and for 8.5 Gt CO_2 (or about 25%) of the total energy system's CO_2 emissions.

Energy-intensive industrial sub-sectors represent about two-thirds of total final industrial energy demand, with just chemicals, iron and steel and cement production accounting for almost 60% of the industrial total. The significant contribution of these three sub-sectors to industrial energy demand, together with the release of CO_2 emissions that are inherently produced as part of the reactions taking place in these processes, result in these industrial activities being responsible for almost 70% of total industrial CO_2 emissions.

Each of these industrial segments has specific characteristics that lead to differing starting levels of energy consumption and CO_2 emissions: raw material needs, processing conditions, product quality requirements – the list is long. The singularities of each industrial sub-sector need to be well understood to identify sustainable strategies that can drastically reduce its emissions footprint. For instance, while the chemical sector is the highest industrial energy consumer, it is only the third-largest industrial CO_2 emitter, after cement and iron and steel, as a result of a lower dependency on coal and the energy consumed as feedstock (or "raw material") being locked into the product – and not resulting in CO_2 emissions until the product decomposes (Figure 12).

Figure 12. Final energy demand and direct CO_2 emissions by industrial subsector, 2017



Notes: *Final energy demand* includes energy consumption in blast furnaces and coke ovens, as well as chemical feedstock. Analysis above uses the Energy Technology Perspectives modelling framework.

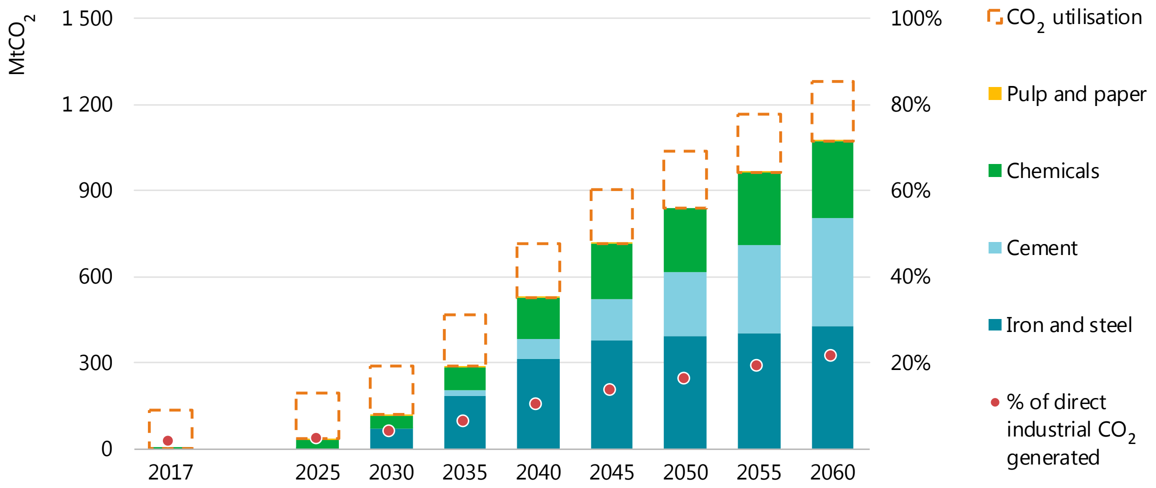
Chemicals, iron and steel and cement account for almost 60% of final industrial energy demand and 70% of direct industrial CO_2 emissions.

The CTS sees industrial direct CO_2 emissions being reduced by 40% by 2060 from current levels and 30% cumulatively compared to the RTS. This level of emissions reductions requires a portfolio of strategies including energy and material efficiency, switching to alternative fuels and feedstock (such as biomass or waste), and deployment of innovative processes that rely on renewable energy sources and/or that facilitate the integration of CCUS.

CCUS becomes an important technology in the long term in the industrial sector, contributing around 15% to the cumulative emissions reductions reached in the CTS compared to the RTS. Carbon capture generally proves to be a cost-effective measure in key energy-intensive industries in the CTS compared to other alternative primary processes that rely on electricity or biomass. This is either because CO_2 is relatively easy to separate, or due to fossil fuel prices remaining low relative to those of electricity and biomass (the latter of which increase in demand over the analysed period), or through a combination of both. In 2060 around 1 Gt CO_2 is captured for storage and 0.2 Gt CO_2 for use in other industrial processes in the CTS, jointly equivalent to about 20% of the total direct CO_2 emissions generated in the industrial sector in that year (Figure 13).

Iron and steel, cement and chemicals are the main industrial activities that deploy carbon capture technologies for storage, with almost half, a quarter and just over a quarter being their cumulative contributions respectively. The industrial applications of CO_2 in this context are analysed within the boundaries of energy-intensive industrial activities, with a focus on chemical production such as urea and methanol (See Box 2 for a description of additional manufacturing applications of CO_2).

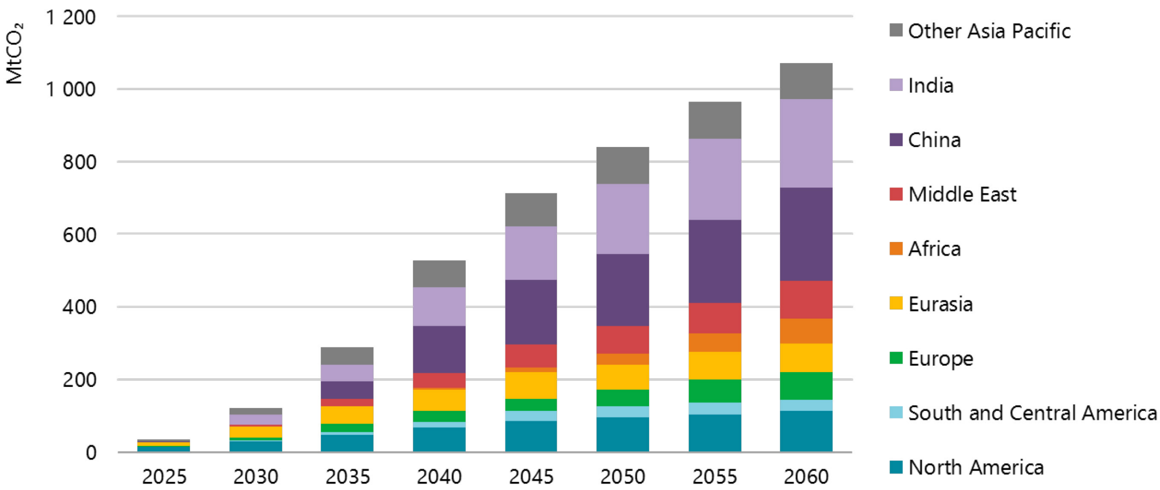
Figure 13. Captured CO_2 for storage by industrial sub-sector and for utilisation in the CTS



Notes: *CO_2 utilisation* refers to its application for the production of urea and methanol. Analysis above uses the Energy Technology Perspectives modelling framework.

Around 20% of direct industrial CO_2 emissions generated are captured either for storage or use in 2060 in the CTS.

Figure 14. Captured CO_2 for storage in industry by region in the CTS



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

Asia accounts for more than half of industrial CO_2 emissions captured for storage in 2060 in the CTS.

Asia absorbs more than half of the total industrial CO_2 emissions captured and stored in the CTS in 2060, of which China and India each account for close to one quarter of the global share (Figure 14). The growing demand for bulk materials is expected to be met mostly by Asia, as economies in the region develop further their infrastructure and buildings stock, in combination with a growing population demanding more consumer goods. This puts more pressure on the need to reduce emissions. For instance, by 2060 India is set to more than quadruple its demand for crude steel and almost triple its demand for cement in the CTS, while countries of the Association of Southeast Asian Nations (ASEAN) nearly quadruple their demand for crude steel on average, and in some cases double their demand for cement. While Chinese cement and crude steel production is expected to decrease in the CTS, as its industrial sector transitions to less energy-intensive and higher value-added activities, the country still absorbs around 30% of global production of both materials in 2060.

Box 2. Opportunities for the application of CO_2 in manufacturing

Interest is growing in novel ways of using CO_2 as a feedstock for products that have a market value. Alongside the economic driver, CO_2 use may provide a number of other services to society, such as climate change benefits, the substitution of fossil fuels as a feedstock for fuels and materials, and the conversion of renewable electricity to hydrocarbons that are compatible with existing infrastructure. The last ten years have seen a sharp rise in the amount of public and private spending on research and development (R&D) programmes and projects using CO_2 to make valuable products, mainly in North America and Europe (IEA, 2018a).

The range of potential manufacturing applications to use CO_2 is wide and includes conversion to chemicals and building materials. Most CO_2 utilisation technologies are still at an early stage of development and neither their technical performance nor their cost-effectiveness are well understood. For that reason, assessing the market potential for CO_2-based products is very challenging.

In building materials, CO_2 can be used as an ingredient in the concrete production process, either as part of the binding material (cement), as a component of the filler (aggregate), or by replacing water during the process of concrete curing. Aggregate production that uses CO_2 can be based on natural alkaline minerals (e.g. magnesium- and calcium-rich silicates) or industrial by-products (e.g. iron slag and coal fly ash). The main challenges with the use of CO_2 in the production of aggregates are the large amounts of energy and minerals required per tonne of CO_2 used, resulting in high processing costs (IEA, 2018b). The availability of these industrial by-products is likely to be limited in the long term, as power generation shifts away from coal-based technologies and secondary steel production is more widely adopted to reduce the CO_2 footprint of steel. The low market value of aggregates presents an additional commercial challenge.

The role of CCUS in fuel transformation

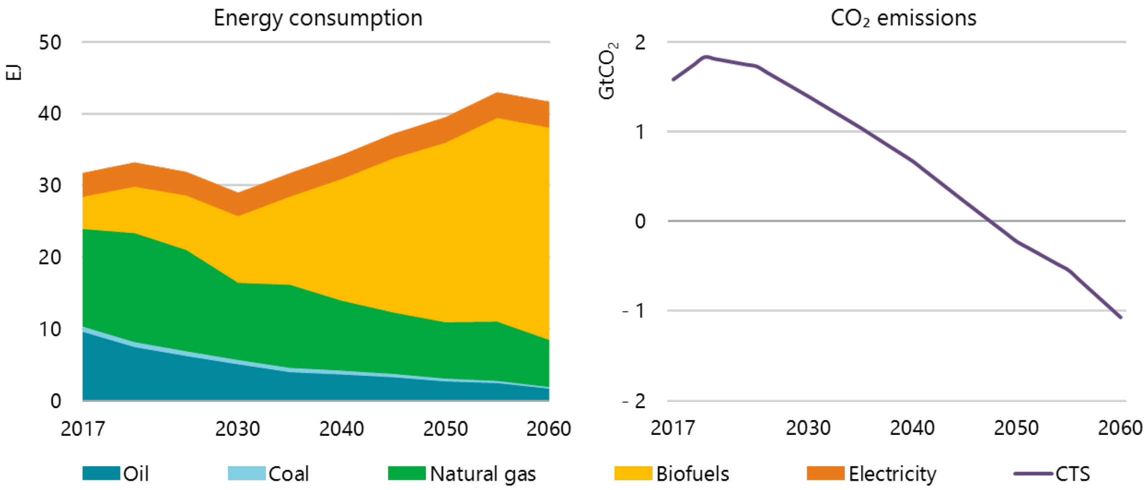
The fuel transformation sector covers the use of energy for coal mining, oil and gas production, and the further conversion of primary energy into final energy carriers for use in buildings, industry and transport (except electricity and heat).[3] In 2017 fuel transformation accounted for 32 EJ or, on average, 5% of global total primary energy demand, with oil refining being responsible for half of the sector's energy demand, and oil and gas extraction for around a third. Depending on the role of these activities in a country's economy, the impact of the fuel

[3] Deviating from International Energy Agency (IEA) energy balance conventions, energy use for blast furnaces and coke ovens is not accounted for in the fuel transformation sector, but instead in the industrial sector due to the close connection of these processes to iron and steel making.

transformation sector on primary energy demand can be quite different from the world average, such as in South Africa with 15% or Canada with 14%. With annual CO_2 emissions of 1.7 Gt CO_2 in 2017, fuel transformation was responsible for 5% of global energy- and process-related CO_2 emissions.

In the CTS, declining demand for fossil fuels and greater uptake of biofuel production for the transport sector lead to a drastic change in the consumption of energy in the fuel transformation sector (Figure 15). Energy use for fossil energy extraction and oil refining trend downwards, while growing demand for liquid and gaseous biofuels, in particular in the transport sector, lead to increasing biofuel production. Despite efficiency improvements, this results in growing bioenergy consumption in the fuel transformation sector due to conversion losses during biofuel production.

Figure 15. Global energy consumption and CO_2 emissions of the fuel transformation sector in the CTS



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

Declining demand for fossil fuels and increasing biofuel production for the transport sector drive the consumption of energy in the fuel transformation sector in the CTS.

In the CTS, around 31 Gt CO_2 are cumulatively captured and stored between 2017 and 2060 in the global fuel transformation sector (Figure 16), with CCUS in the fuel transformation sector accounting for almost 30% of all the CO_2 being stored in the CTS and 4% of the cumulative reduction in global CO_2 emissions between the RTS and CTS.

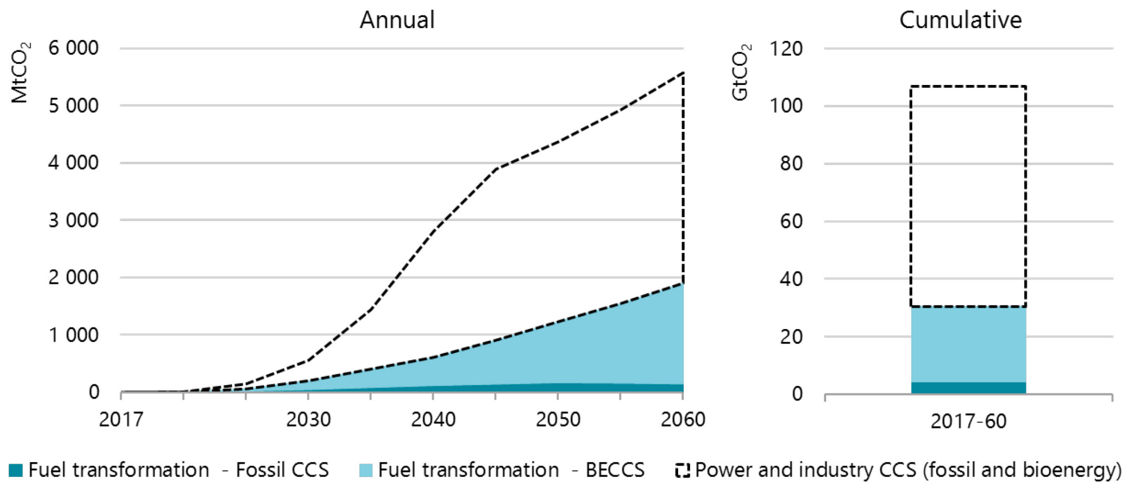
Most of the CCUS deployment in the fuel transformation sector is linked to the production of biodiesel or bioethanol, which are needed to decarbonise the transport sector. These biofuel plants equipped with carbon capture and storage (CCS) are responsible for the fuel transformation sector reaching net negative CO_2 emission levels of -1.1 Gt CO_2 in 2060. By capturing and storing the CO_2 from the combustion of biomass, such as at a bioethanol plant, biogenic CO_2 is removed from the natural carbon cycle instead of being re-released into the atmosphere. Thus, bioenergy with CCS (BECCS) at biofuel production plants can provide negative CO_2 emissions that can offset emissions in other parts of the energy system. The future availability of sustainable biomass will be a key factor for BECCS deployment (Box 3).

Capturing CO_2 from biofuel production processes also requires only moderate additional investment and energy, since the off-gas streams of biofuel plants are typically characterised by high CO_2 concentrations, resulting in relatively low CO_2 avoidance costs in the range of USD 20–30 per tonne of CO_2 (tCO_2) (Global CCS Institute, 2017).[4]

Natural gas processing is a further lower-cost application of CCUS in fuel transformation, accounting for 14% of the CO_2 stored in the sector in the CTS. The CO_2 separation is an inherent part of the gas processing, with CO_2 and other impurities (water, hydrogen sulphide [H_2S]) needing to be removed to meet pipeline quality standard. The CO_2 content of raw natural gas being extracted can vary significantly, from almost CO_2-free natural gas in Siberia to a CO_2 content of 72% to 80% in the Carmito Artesa field in Mexico (IEA, 2008). Instead of being vented into the atmosphere, the separated CO_2 can be stored in an often nearby depleted oil or gas field, or used for CO_2-EOR.

With CO_2 storage widely available in the CTS, CCU plays almost no role in the fuel transformation sector. Only 40 Mt CO_2 or 0.1% of the cumulative CO_2 captured in the fuel transformation sector, is used for the production of synthetic fuels.

Figure 16. CO_2 captured and stored in the fuel transformation sector in the CTS on an annual basis (left) and cumulatively (right)



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

Over 80% of cumulative CO_2 captured and stored in the fuel transformation sector in the CTS is from biogenic sources.

[4] For example, the CO_2 concentration in the off-gas stream of a bioethanol plant (conventional and advanced) reaches around 99% (on a dry basis), so that other than removing water no further treatment is needed before compressing the CO_2 for transport and storage.

Box 3. How much bioenergy is available?

Bioenergy can play an important role in reducing carbon emissions from the energy sector. In the CTS, with global use of 125 EJ in 2060, bioenergy becomes the largest primary energy source. Bioenergy is a very versatile energy source and can help to reduce CO_2 emissions in various parts of the energy system: as liquid fuel for the hard-to-decarbonise aviation and shipping sectors; in industry as feedstock and fuel for processing; and in the form of biogas as fuel for flexible gas turbines in the power sector. In addition, the use of bioenergy can in combination with CCS produce negative emissions, offsetting remaining CO_2 emissions in other parts of the energy system, or counterbalancing near-term carbon budget "overshoot" while still keeping more ambitious climate targets within reach. To play this role, however, bioenergy needs to be produced in a sustainable way, not leading to unmanaged impacts on the environment or causing harmful social or economic consequences.

A wide range of estimates for the availability of biomass for energy purposes is apparent in the relevant literature, ranging from levels close to zero to levels well in excess of today's total energy use (1 500 EJ annual biomass availability). Analysis of the various studies and meta-studies suggests that:

- There seems to be consensus that up to 100 EJ could be delivered by 2050 without serious difficulties.
- Potential within the 100 EJ to 300 EJ range may still be considered reasonable, but the risks of delivery increase as the estimate rises and therefore a number lower down this range is to be preferred.
- The amount of feedstock supply needed to meet the RTS and CTS (95 EJ to 125 EJ per year) is within the range of many of these estimates. Its delivery will require significant contributions from wastes and residues and from energy crops, and therefore measures will be needed to mobilise all three resources while ensuring high levels of lifetime carbon benefits and avoiding other serious sustainability concerns.

A number of factors and actions could make the required supply easier to achieve and potentially lead to biomass availability at the high end of these ranges or even higher:

- Improving food crop yields through improved crop varieties and management practices, but especially by narrowing the "yield gap" between best practice and achieved food production, thus enabling more to be produced on less land and potentially freeing land for energy production.
- Improvements in the land efficiency of animal husbandry, which could make more efficient use of the land used to raise animals for meat and dairy products by increasing intensity and so freeing land for other purposes.
- Improving the efficiency of food production, notably by reducing food waste. It is estimated that some 30% of the food produced globally is wasted (e.g. lack of "cold chains" during transport in developing countries or consumer waste in developed countries).
- Afforestation of derelict and abandoned land, which could provide significant resources for sustainable local food and energy production. When planted with mixtures of trees, grasses and food crops, such areas can provide food and bioenergy on a sustainable basis while improving land quality.

- Maximising the productivity of any land that it is decided should be dedicated to energy production by using energy crops that are best adapted to the land and climate, taking both production efficiency and energy conversion processes into account.
- Improved waste management practices and rapid implementation of waste-to-energy systems.
- Co-producing food and energy, either by efficient use of residues and co-products for energy purposes, or by producing food and energy products by intercropping or crop rotation.
- Maximising the efficiency of use of bioenergy resources, for example through co-generation and co-production of electricity, heat and fuels, alongside biochemicals where appropriate.

Sources: IEA (2017a), *Energy Technology Perspectives 2017*, www.iea.org/etp2017/; IEA (2017b), *Technology Roadmap: Delivering Sustainable Bioenergy*, www.ieabioenergy.com/wp-content/uploads/2017/11/Technology_Roadmap_Delivering_Sustainable_Bioenergy.pdf.

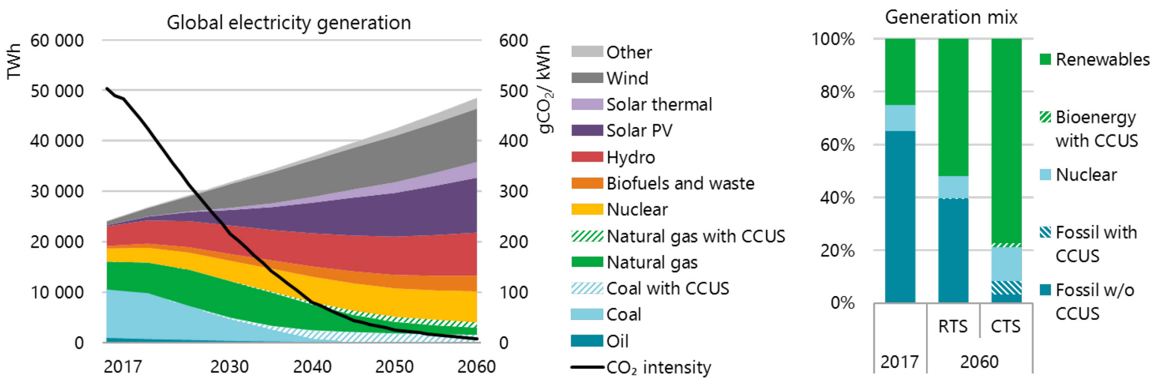
The role of CCUS in power generation

At a global level, electricity has been the fastest-growing final energy source (i.e. energy consumed in agriculture, buildings, industry and transport), increasing at an average annual rate of 3.2% over the last four decades. As a result, electricity is today only second to oil in global final energy demand, with a share of 19%, and is responsible for almost 40% of global CO_2 emissions.

In the CTS, the share of electricity in global final energy demand almost doubles to 36% by 2060 as end-use sectors increasingly electrify. For the end-use sectors, the opportunity to reduce emissions by substituting fossil fuels with low-carbon electricity is the key driver behind this electrification trend (reducing air pollution in cities is another). In the transport sector, the share of electricity in the sector's energy demand in the CTS grows rapidly from merely 1% today to 27% by 2060. The buildings sector today meets 32% of its energy needs through electricity, but further potential for electrification exists; in the CTS, the share of electricity almost doubles in 2060 to 60%, notwithstanding strong energy efficiency measures. In the industrial sector, the share of electricity in energy demand in the CTS reaches 27% by 2060, compared with 20% today.

Global electricity generation is virtually decarbonised by 2060 in this scenario, with the average CO_2 intensity falling from 484 grams of carbon dioxide per kilowatt hour (g CO_2/kWh) in 2017 to 8 g CO_2/kWh by 2060 (Figure 17). To achieve this, the generation share from fossil fuels without CCS falls from 65% in 2017 to 3% in 2060, while the share of renewables more than triples from 25% to 77% (excluding BECCS). Nuclear increases its share from 10% to 13% and CCS (including BECCS) reaches a share of 7% in 2060. Gas-fired power generation without CCS peaks in 2030, reflecting the changing nature of gas-fired power plants: from producing electricity to providing flexibility to support the integration of variable renewables (namely wind and solar photovoltaic [PV]), which reach a share of 44% in the global electricity mix in 2060. Electricity storage and demand response are further flexibility options, reaching combined 1 430 gigawatts (GW) by 2060.

Figure 17. Global electricity generation in the CTS



Notes: TWh = terawatt hour; w/o = without. Analysis above uses the Energy Technology Perspectives modelling framework.

The share of low-carbon technologies in global power generation is about 97% in 2060, with the average CO_2 intensity approaching zero by 2060 in the CTS.

CCUS delivers 15% of the cumulative CO_2 reductions needed in the power sector to move from the RTS to the CTS (Figure 18). Two-thirds of the emissions reductions from CCUS are linked to coal-fired power generation equipped with CCUS. Global coal-fired capacity with CCS reaches 265 GW in 2060 in the CTS, with China accounting for 24% of the capacity, followed by ASEAN countries with 18% combined, and India with 11%. Coal-fired power generation with CCUS stagnates after 2045, as coal-fired electricity generation with CCUS becomes too carbon-intensive due to the non-captured CO_2 emissions.[5] Without higher rates of capture or co-firing with biomass, the global average CO_2 intensity of electricity from coal plants with CCUS would be 110 g CO_2/kWh, compared with 8 g CO_2/kWh for the global average electricity mix. Biomass co-firing in CCUS coal power plants can further reduce the CO_2 intensity of these facilities to an average of 30 g CO_2/kWh (based on a 10% co-firing rate) and therefore extend their operational lifetime in the CTS.

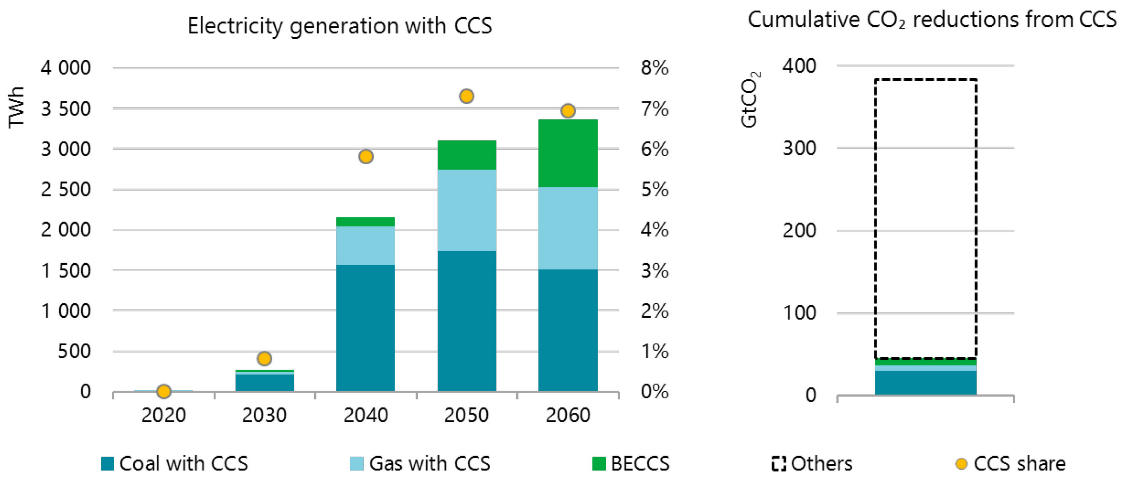
The global capacity of gas-fired power generation with CCUS reaches 235 GW in 2060 in the CTS, providing around 2% of electricity generation. Around a fifth of this global capacity is located in the United States. The CO_2 intensity of CCUS-equipped gas plants in 2060 averages 55 g CO_2/kWh globally, roughly half that of coal with CCUS (without higher capture rates or biomass co-firing), but also above the global average intensity across all fuels. As a consequence, gas-fired power generation with CCUS stagnates after 2050 in the CTS.

The deployment of BECCS in power generation creates negative emissions that can offset remaining CO_2 emissions in the power sector itself or in other parts of the energy system. While fossil power generation with CCUS stagnates after 2050, BECCS rapidly increases due to the increasing pressure to decarbonise the power sector. By 2060, global BECCS power capacity reaches 115 GW in the CTS, and accounts for around 2% of both global electricity generation and the cumulative CO_2 reductions in the power sector between the CTS and RTS.

[5] The CTS assumes a rate of CO_2 capture from coal-fired power plants of between 85% and 90%; however new studies have highlighted that up to 100% capture is technically feasible and would not be associated with significantly higher costs (IEAGHG, 2019).

BECCS in the power sector can be realised in the form of co-firing in coal- or gas-fired power plants with CCS, or through dedicated BECCS power plants. For dedicated BECCS plants, a promising option seems to be biomass gasification with CO_2 removal from the produced syngas, which is then combusted in a combined-cycle turbine. This biomass integrated gasification combined-cycle (BIGGC) technology not only allows the use of a variety of feedstocks for gasification, but the produced syngas can also be used for other purposes, such as the production of synthetic fuels or feedstocks. Further BECCS technology options include circulating fluidising bed (CFB) combustion in combination with post-combustion CO_2 capture from the flue gas, or an oxy-fuel combustion process using oxygen instead of air and resulting in a CO_2-rich flue gas. They also allow the use of various qualities of biomass or waste feedstocks. There are currently no BECCS power plants operating at commercial scale, although construction of a 50 megawatt (MW) pilot plant with CO_2 capture in Japan started at the end of 2018, and a 50 MW pilot with CO_2 capture is underway at the Drax power station in the United Kingdom.

Figure 18. Global electricity generation with CCS and cumulative CO_2 reductions from CCS in the CTS relative to the RTS



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

Power generation from fossil CCS stagnates after 2050 due to its remaining non-captured CO_2 emissions, while BECCS continues to grow.

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3. The implications if CO_2 storage were limited

CCUS technologies play an important role in meeting the ambitions of the CTS as part of a least-cost portfolio of technologies and measures. Previous IEA analysis has shown that the role of CCUS increases with the level of climate ambition (IEA, 2017) and the IPCC has highlighted the critical importance of CDR technologies, particularly BECCS, in limiting future temperature increases to below 2°C (IPCC 2018). However, the reliance on CCUS technologies in climate scenarios stands in contrast to the relatively limited deployment of CCUS facilities today.

In order to understand the energy system-wide implications should CCUS not be available at the scale envisaged in the CTS, a limited CO_2 storage variant (LCS) was considered. In the LCS, despite increased climate ambition, the vast global CO_2 storage resources would not be developed due to a lack of supportive policy or other economic or social factors. Only storage resources that would be developed without significant changes to the current policy and political climate would be available in the LCS, with total cumulative CO_2 storage limited to under 10 Gt CO_2, the level in the RTS.

Is CO_2 storage likely to be limited?

While there is a high degree of confidence that global storage resources are well in excess of future requirements, even under highly ambitious scenarios, failure to develop these resources in a timely manner could act as a brake on CCS deployment. Key factors that could limit CO_2 storage availability in practice include:

Lack of investment in CO_2 storage exploration and assessment. Confidence in the availability of adequate, secure and safe CO_2 storage resources will be a prerequisite for investment in CO_2 capture facilities and CO_2 transport infrastructure. The CO_2 storage assessment process must identify geotechnical uncertainties related to containment,[6] injectivity and capacity, in addition to considering economic, social and regulatory factors. Experience has demonstrated that this process can take anywhere from 1 to 15 years, depending on the storage option (IEAGHG, 2011).

Proximity of emission sources to CO_2 storage. While CO_2 can be transported over long distances by pipeline or ship, the availability of storage in proximity to emissions sources will be an important commercial consideration. The availability of CO_2 storage near large industrial or power facilities could be limited by geotechnical factors, competition with underground resources in terms of pore spaces (oil, gas, coal, fresh water), or surface constraints (including urban areas, densely populated areas, environmentally sensitive areas, existing infrastructure, protected areas such as parks).

[6] Containment refers to ensuring that any injected CO_2 should not migrate out of the storage complex. Injectivity is the amount of CO_2 that can be injected at the rate that it is delivered over time. Capacity is the total CO_2 volume that can be practically injected and stored.

Limited business case for CO_2 infrastructure investment. Developing CO_2 transport and storage infrastructure for the sole purpose of removing and disposing of CO_2 emissions is a relatively new commercial proposition, and one that would only be viable in the context of a strong climate policy response. These investments bring additional complexity due to the nature of the infrastructure, which involves sub-surface risks and uncertainties, long-term liability considerations and the need to co-ordinate and align CO_2 supply with storage development (a "chicken and egg" problem). Public–private partnerships have been proposed to develop CO_2 storage and build and operate related transport infrastructure in order to overcome some of these challenges in the early deployment phase.

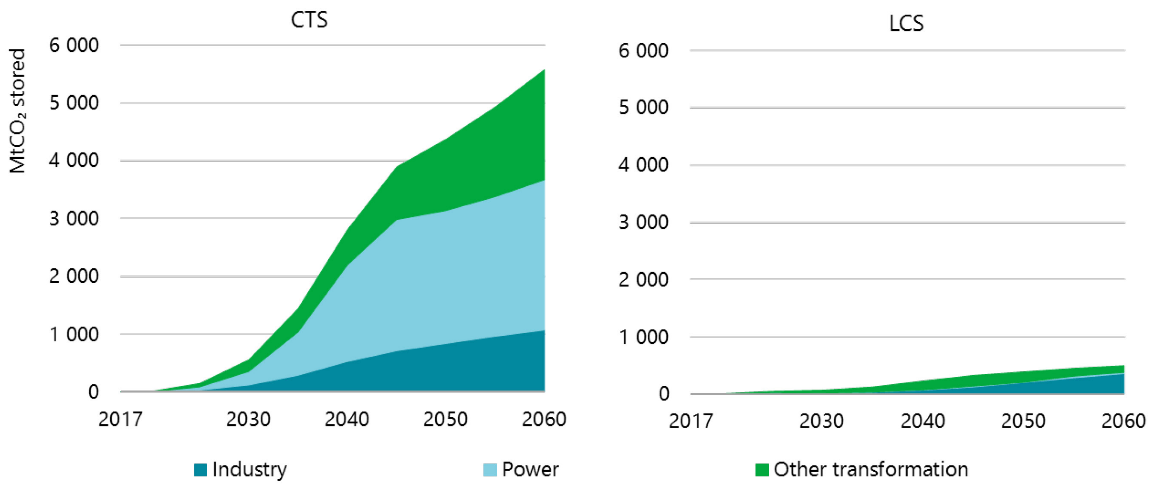
Legal and regulatory uncertainty. Stable and transparent legal and regulatory frameworks are crucial to enable commercial investment in CO_2 storage. Countries such as Australia, Canada and the United States, and the European Commission, have introduced comprehensive legal and regulatory frameworks, but in some regions uncertainty around long-term liability and ownership of the stored CO_2 remains a barrier to commercial investment. A lingering legal impediment to offshore CO_2 storage is the failure of countries to ratify the amendment to the London Protocol to the Convention on the Prevention of Marine Pollution, which would allow for the transport of CO_2 across borders for offshore geological storage.

Public acceptance. Social and political acceptance could restrict the availability of CO_2 storage resources, particularly for onshore sites. In the past, CCS projects in Germany, Denmark and Poland, for example, have failed in part due to local opposition to CO_2 storage.

Exploring the implications of limiting CO_2 storage

The LCS would limit the available CO_2 storage to less than 10 Gt CO_2, or 9% of the cumulative CO_2 stored in the CTS (Figure 19). The industrial sector would absorb the largest share of the available storage, with 4.9 Gt CO_2 stored in the period to 2060, with fuel transformation having 4.4 Gt CO_2 and the power sector only 0.4 Gt CO_2.

Figure 19. CO_2 stored by sector in the CTS and LCS



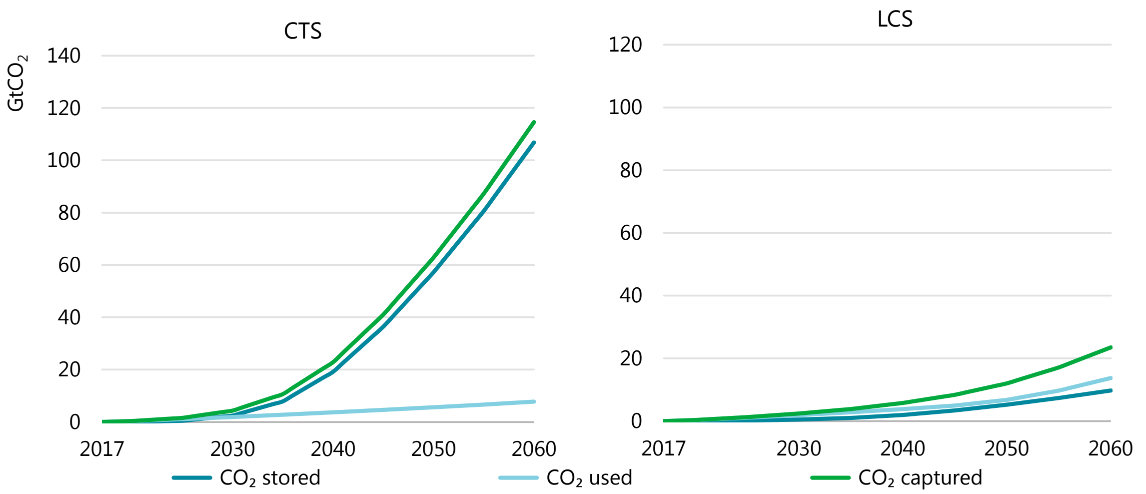
Note: Analysis above uses the Energy Technology Perspectives modelling framework.

Cumulative CO_2 storage would be limited to under 10 Gt in the LCS.

Limited availability of CO_2 storage in the LCS would lead to an 80% reduction in total CO_2 captured across the period. CO_2 capture would not be directly limited in the LCS, but rather it would be partially constrained by the amount of CO_2 that can be stored.

Demand for CO_2 for use is not assumed to be constrained, but is determined by the competitiveness of the CO_2-based production and therefore the demand for CO_2-based products. In the CTS, CO_2 use would be largely limited to the existing mature processes that are widely adopted, such as methanol production, and although there are also applications beyond these traditional processes in fuel production, they would not be widely deployed by 2060. If there were limitations on CO_2 storage as in the LCS, captured CO_2 would be used more extensively in these other novel applications, primarily for fuel production. By 2060 14 Gt CO_2 would be used cumulatively in these processes in the LCS (Figure 20).

Figure 20. CO_2 captured, used and stored in the CTS and LCS



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

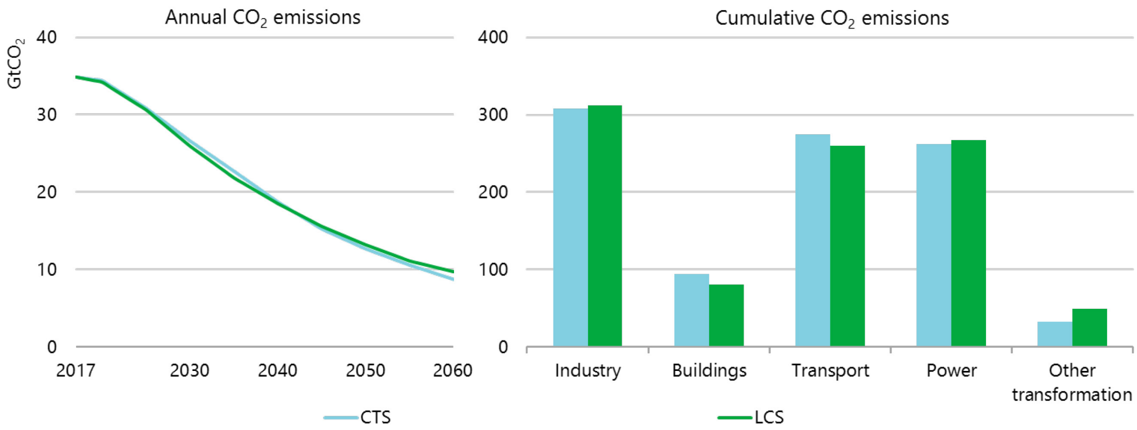
Limited availability of CO_2 storage would lead to much lower levels of CO_2 capture, and an increase in CO_2 use.

A shift in sectoral contributions

Limiting CO_2 storage while reducing energy- and process-related CO_2 emissions to the same extent as in the CTS would require the emissions reductions achieved through CCUS to be achieved through other measures. In some sectors, CCUS could be replaced with other emissions reduction measures, although generally at higher cost. But in some industrial sub-sectors, no alternative scalable low-carbon production options are available.

As a result, the industrial, power and fuel transformation sectors would emit more than in the CTS – the cumulative emissions from fuel transformation would rise by 17 Gt CO_2, from industry by 4.8 Gt CO_2 and from power generation by 5.7 Gt CO_2 in comparison to the CTS. This would require even more aggressive emissions reductions from the buildings and transport sectors, with a reduction of 15% and 6% needed respectively relative to the CTS (Figure 21). The emissions reductions in the transport and buildings sectors would be in part driven by a range of changes to the built environment, efficient technologies and behaviour. These are not pursued to the same high extent in the CTS, as the level of deployment reached exhibits higher costs and political, social and practical challenges than CO_2 storage.

Figure 21. Global CO_2 emissions and cumulative emissions by sector in the CTS and LCS



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

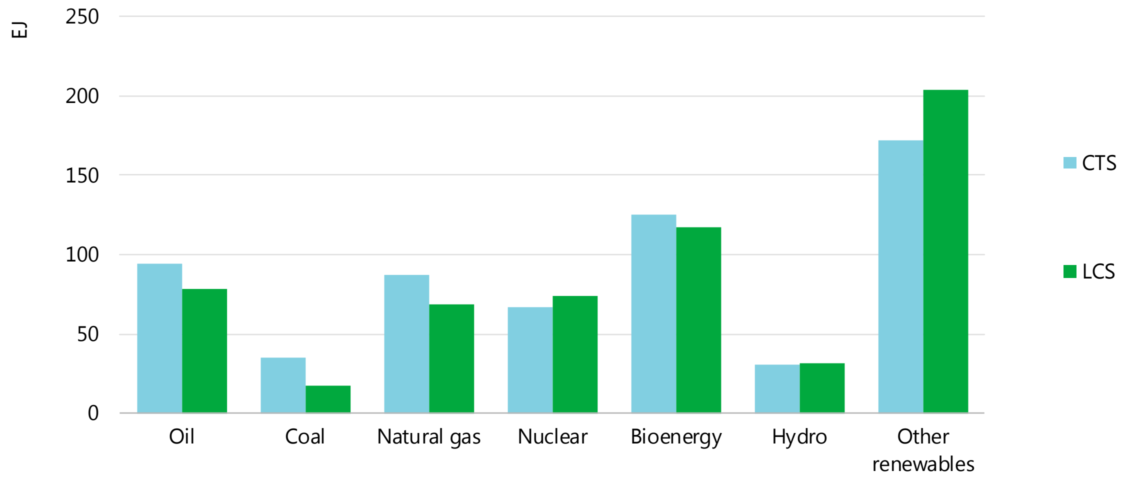
Overall emissions reductions in the LCS would equal those in the CTS; however, the sectoral contributions would change.

A sharp(er) decline in fossil fuel use

Global primary energy demand for oil, coal and natural gas would be reduced by 25% in the LCS compared to the CTS in 2060 (Figure 22). Coal demand would be most affected, with its consumption more than halved in 2060 compared to the CTS – a reduction equivalent to the combined coal consumption of India and all of Latin America in 2017. This would be primarily driven by lower coal consumption in some industrial sectors, such as iron and steel making, and the complete phase-out of coal in power generation just before 2050. Overall, the 2060 share of fossil fuels in the global primary energy mix would fall from 35% in the CTS to 28% in the LCS, while the use of renewables, mainly for power generation, would increase driven by the need for more low-carbon electricity in various parts of the energy system. The transport sector's oil demand in 2060 would fall by 12%, as transport patterns shift away from personal vehicle use towards public and multiple-user modes of transport.

The more rapid decline in fossil fuel demand, and decline in total primary energy demand, compared to the CTS would be driven by the types of ambitious policies that compel significant changes to the built environment, such as the structure of urban areas, and behavioural changes in the transport and residential sectors. These would result in reduced energy and service demand, and the accelerated rollout of energy efficiency measures. For example, the more stringent emissions reduction needed in the transport sector to account for the increased emissions in the other sectors in the LCS would result in passenger activity (measured in passenger kilometres [pkm]) in cars falling by 1% in 2060 relative to the CTS, and a shift to public transport, with a combined 7% higher passenger activity (in pkm) on trains and buses (Figure 23).

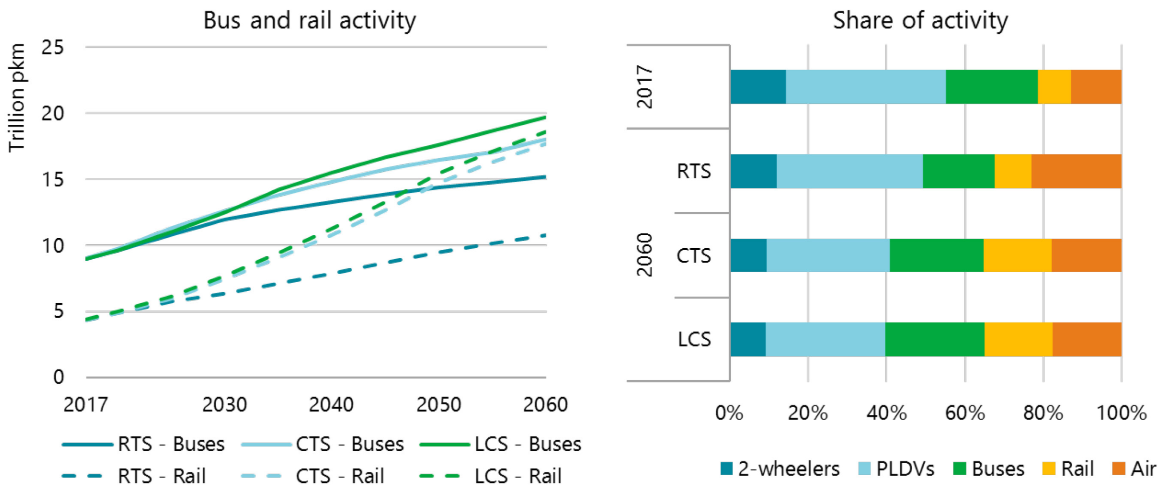
Figure 22. Global primary energy demand by fuel in the CTS and LCS, 2060



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

Primary energy demand for oil, coal and gas combined would be reduced by 25% in the LCS compared to the CTS.

Figure 23. Bus and passenger rail activity, and share of passenger transport activity by mode and by scenario



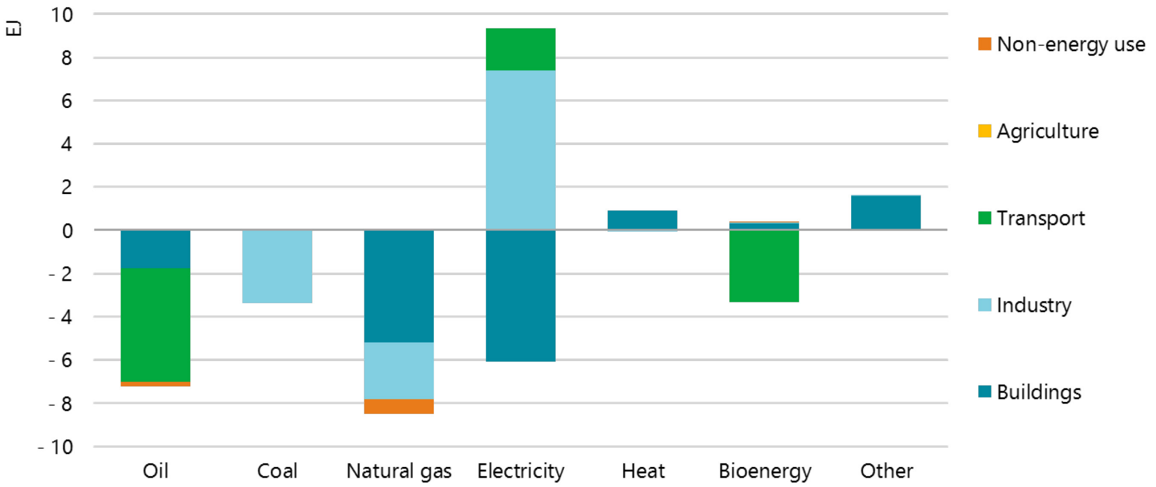
Notes: PLDV = passenger light-duty vehicle. Analysis above uses the Energy Technology Perspectives modelling framework.

Transport activity would shift further from passenger vehicles (PLDVs and 2-wheelers) to bus and rail in the LCS in comparison to the CTS.

Greater electrification of end-use sectors

The implications of limiting CO_2 storage become more apparent when considering the changes in global final energy demand in the LCS, relative to the CTS (Figure 24). Final energy demand for oil, gas and coal would be reduced in the LCS in part through the more efficient use of these fuels, but in particular through substitution by electricity. Global final electricity demand in 2060 would increase by 900 TWh (or 2%) in the LCS relative to the CTS. This shift towards electrification in the LCS would be largely driven by industry, accounting for 80% of the demand growth in industry and transport, whereas buildings' electricity consumption would be reduced by 9% through energy efficiency measures. In the LCS, electricity would account for 39% of all final energy demand in the global industrial sector in 2060, an increase of two percentage points compared with the level achieved in the CTS. This growth in electricity demand would be primarily driven by indirect electrification to produce hydrogen through electrolysis. This hydrogen would be then used, for example, as a reducing agent in the iron and steel sector, or as feedstock in the chemical industry for ammonia production or in combination with captured CO_2 for producing methanol.

Figure 24. Global final energy demand changes in the LCS relative to the CTS, 2060



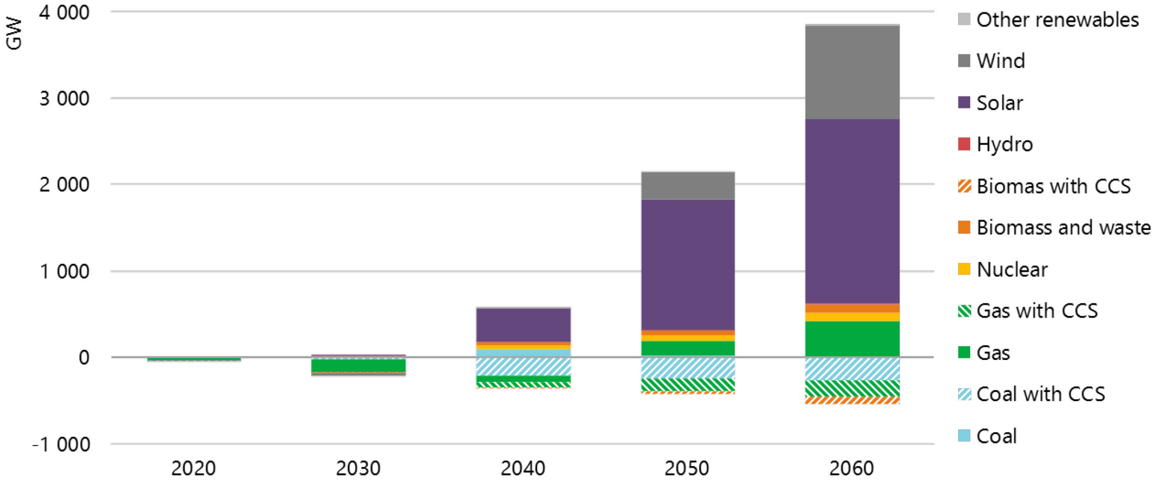
Note: Analysis above uses the Energy Technology Perspectives modelling framework.

Global final electricity demand would increase by 900 TWh (3 EJ) in 2060 in the LCS relative to the CTS, just under the total electricity consumption of Japan in 2017.

In addition to the increase in electricity demand for industrial hydrogen in the LCS, the use of electricity to produce hydrogen would also occur in the fuel transformation sector. The hydrogen would be combined with captured CO_2 to produce power-to-liquids (PtL) and power-to-gas (PtG) fuels. By substituting fossil liquid fuels or natural gas, these CCU pathways could achieve CO_2 reductions similar to storing the CO_2 instead. Around 4 700 TWh of electricity would be consumed in 2060 in the LCS for these synthetic fuel technologies in fuel transformation.

The combined impact of increased electricity consumption in industry (and to a lesser extent in transport) and for synfuel production in fuel transformation would lead to a 13% (6 000 TWh) global increase in electricity generation in 2060 in the LCS compared to the CTS. This additional generation would require around 3 300 GW of additional power generation capacity in 2060, a 17% increase compared to the CTS (Figure 25). These additional capacity needs would be mostly covered by solar PV and wind, with around half from dedicated solar PV and onshore wind plants at locations with good resource conditions for the production of hydrogen and synthetic hydrocarbon fuels.

Figure 25. Changes in global installed power generation capacity by fuel in the LCS relative to the CTS



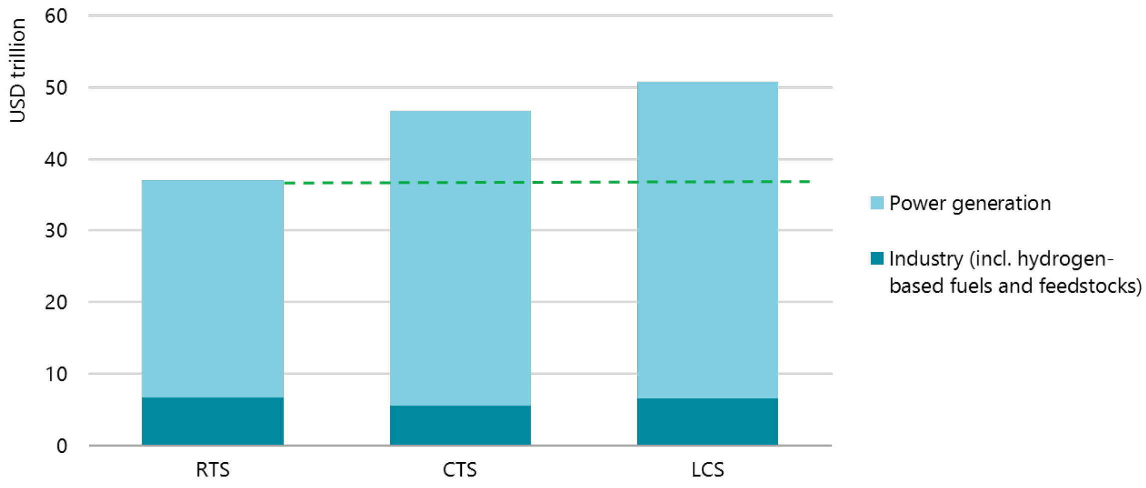
Note: Analysis above uses the Energy Technology Perspectives modelling framework.

The LCS would need additional power capacity of 3 300 GW in 2060 over the CTS, equivalent to today's capacity of China, India and United States combined.

Changes in investment needs

Meeting the emissions reductions of the CTS with very limited access to CO_2 storage, as in the LCS, would increase the investment needs of the global energy sector. The additional capacity needs of the power sector would have the largest impact on investment requirements, driven by higher final electricity demand (largely from industry) and electricity used for synthetic hydrocarbon fuels from electrolytic hydrogen in the fuel transformation sector. Although cumulative industrial investment in the LCS compared to the CTS (including for synfuel production) would be higher by a rather moderate USD 0.9 trillion, these activities would be the main driver for the investment needs in power generation. Investment in power generation would be USD 3.1 trillion higher in the LCS compared to the CTS. The additional investment that would be needed in power generation, industry and synthetic fuels may appear moderate, representing a combined 9% increase on the CTS total. Relative to the RTS, however, the additional investment needs of the LCS for these three sectors would be USD 13.7 trillion, 40% higher than in the CTS at USD 9.7 trillion (Figure 26). This means that achieving the same CO_2 reductions, and thus climate targets, as in the CTS would increase the investment requirement by 40% if the availability of CO_2 storage were limited.

Figure 26. Investment needs in power generation and industry, cumulative 2017–60, by scenario



Notes: Dashed line represents investment level in the RTS. Analysis above uses the Energy Technology Perspectives modelling framework.

Limiting CO_2 storage would increase the investment needs in power generation and industry by 40% to achieve the same mitigation targets as in the CTS (relative to the RTS).

Box 4. Managing risks associated with innovation

Risk is inherent to innovation projects as they aim to develop and deploy completely new processes or products. Thus risk management becomes critical to making research, development and demonstration (RD&D) projects viable. Final decisions on investment depend on many factors, but two stand out: uncertainty intensity and capital intensity. Investors have different levels of risk tolerance and perception throughout the different phases of the RD&D process.

Financing early phases of research tends to be more uncertain, or with less chance that the estimated return on investment is met, because technology performance is yet to be proven. The design and development phase builds on successful results from previous research activities, lowering the level of uncertainty when performing investment risk assessments.

Finally, the commercial demonstration stage, although characterised by greater capital intensity, has a more manageable risk because prior pilot-scale trials have provided a basis for considerable confidence in the new technology. While uncertainty intensity decreases as the innovation cycle advances, capital intensity tends to increase, mostly because of the gradual process of scaling up. A decision to invest in innovation hinges on what balance between uncertainty intensity and capital intensity the investor can accept.

In the LCS, limiting CO_2 storage would increase the risk, at a systemic level, of failing to meet emissions reduction targets. This would be due to a reliance on some technologies currently at lower levels of maturity, and the lack of availability of CO_2 storage to assist in generating negative emissions in the latter half of the century. In the LCS, there would be a general trend to deploy innovative technologies that are currently at earlier stages of development or deployment. For example, in the iron and steel sector, the electrolytic hydrogen-based direct reduced iron route would be further deployed in the LCS compared to other fossil fuel-based routes that integrate CCS. While for the former there are firm plans for pilot trials to start in 2021, and to complete commercial demonstration by 2035, for the most advanced of the latter family of technologies successful large pilot trials have already been completed, and the first commercial-scale demonstration is planned for 2022.

In the fuel transformation sector, capturing CO_2 from biofuel production processes or gas processing requires only moderate or no additional investment and is a proven technology. Producing synthetic fuels from electricity and CO_2, routes that would be deployed in the LCS, rely on technologies proven only at pilot scale. As earlier stages in the innovation cycle inherently imply greater investment uncertainty, one can conclude that the technology investment assessment for the LCS would have greater levels of uncertainty relative to the CTS.

Achieving net zero would become more challenging

The LCS assesses the implications of limiting CO_2 storage while still meeting the same overall reductions in emissions to 2060 as in the CTS. It does not, however, explore the implications of limited availability of CO_2 storage beyond 2060, in particular how to achieve net zero CO_2 emissions in the second half of the century and even possibly the need to achieve net negative emission levels. From a technology perspective, the only options within the energy sector that are able to reduce the atmospheric stock of CO_2 involve the capture and storage of CO_2 from biomass combustion or conversion.

Limits to CO_2 storage would also limit options such as directly capturing CO_2 from the air to be stored underground. Without these options, from around 2070 the world may need to rely on options outside the energy sector to achieve the climate targets of the Paris Agreement, such as maximising natural CO_2 sinks through increased afforestation, or on the type of social change, like reduced consumption of animal products, that many consider to be beyond the reach of today's political institutions. Such assessments are beyond the scope of this study.

In-depth analysis: Implications for the industrial sector of the LCS

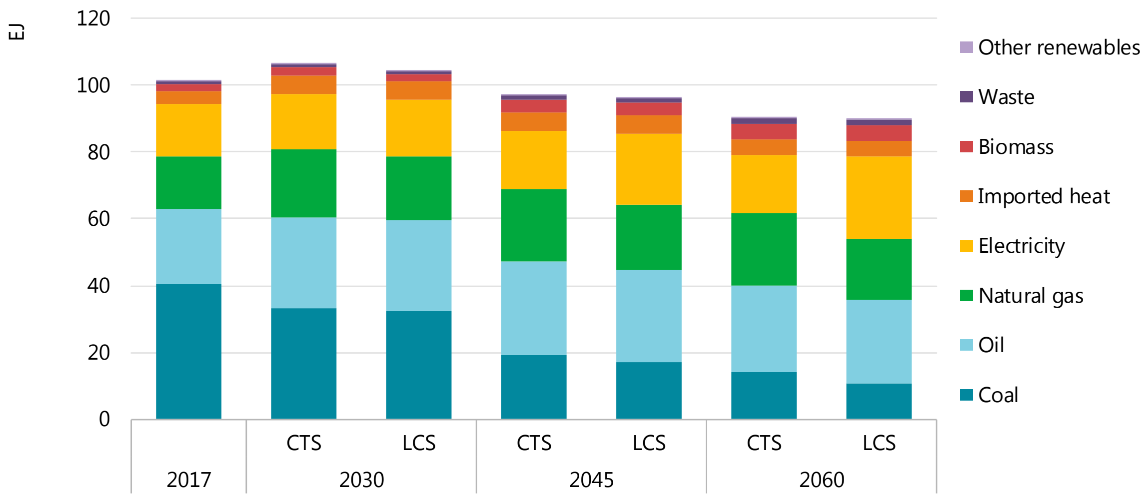
This section explores the implications of limiting CO_2 storage in the industrial sector to the deployment level envisioned in the RTS, but maintaining the same overall system emissions reduction as in the CTS and similar materials production levels.

Limiting the deployment of CO_2 storage would put more pressure on other emissions reduction strategies. With best available technologies widely deployed and cost-effective process integration improvements pursued considerably in the CTS, the focus would be shifted towards material efficiency and new renewables-based processes. Processes that rely heavily on low-carbon electricity, in particular, would become more relevant, as no additional biomass supply is considered in this variant compared to the CTS.[7] Annual direct industrial CO_2 emissions in the period 2040–60 would be around 5% higher compared to the CTS. This increase in industrial sector emissions reflects that by excluding CO_2 storage, the costs for CO_2 abatement would increase. Marginal abatement costs would reach around USD 500/tCO_2 in the period 2040–60 in energy-intensive industrial activities, so that mitigation options in other parts of the energy system would become more economic.

Material efficiency strategies, such as improving manufacturing yields, and reusing and recycling materials, would contribute to reducing the demand for materials, as well as to reducing the CO_2 footprint of materials manufacturing in the CTS compared to the RTS. The analysis exploring the implications of limiting CO_2 storage considers the same degree of policy support for material efficiency strategies as in the CTS, leading to similar levels of materials demand and scrap availability.

Final energy demand in energy-intensive industries would remain at similar levels when limiting CO_2 storage relative to the CTS all the way through 2060 (Figure 27), decreasing to about 90 EJ in that year (22% of total final energy demand). That would not be the case for the energy mix. While in the LCS electricity demand in these industrial sub-sectors would gain 8 percentage points in 2060 as a share of their total final energy demand compared to the CTS, fossil fuels would compensate for that shift with an equivalent decline, of which coal accounts for nearly half. This reflects a shift from fossil-based processes integrating carbon capture to electricity-based processes in the LCS benefiting from low-carbon power generation.

Figure 27. Final energy demand for energy-intensive industries in the CTS and LCS



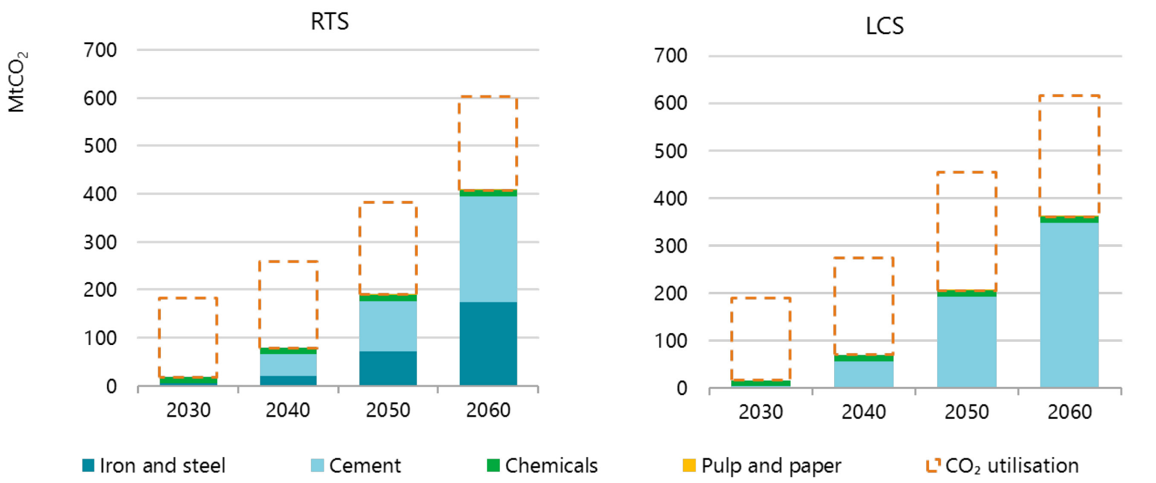
Notes: *Final energy demand* includes energy consumption in blast furnaces and coke ovens, as well as chemical feedstock. Analysis above uses the Energy Technology Perspectives modelling framework.

If CO_2 storage were limited, electricity would gain share in industrial energy demand to the detriment of fossil fuels in 2060.

[7] Maximum sustainably sourced bioenergy feedstock is considered to be 130 EJ globally in 2060 both in the CTS and in the limited CO_2 storage variant.

The RTS sees 5 Gt CO_2 captured for storage cumulatively by 2060, reaching 4% of total industrial direct emissions generated in that year, as a result of projects in the pipeline and the expectation of continued roll-out thereafter. The limited CO_2 storage variant of the CTS would see the same level of cumulative CO_2 captured and stored, but with a different distribution across industrial applications (Figure 28). In a limited CO_2 storage context, cement would attract most of the industrial carbon capture deployment as the sector has fewer alternative options available to deliver such level of emissions reductions. Interestingly enough, CO_2 utilisation would increase by a quarter in 2060 compared to the CTS, as a result of limiting CO_2 storage. This would occur to sustain the greater need for feedstock CO_2 obtained from non-fossil fuel sources, as chemical production shifts away from fossil fuel-based production routes.

Figure 28. Captured CO_2 for storage by industrial sub-sector and for utilisation in the RTS and LCS



Notes: *Final energy demand* includes energy consumption in blast furnaces and coke ovens, as well as chemical feedstock. Analysis above uses the Energy Technology Perspectives modelling framework.

If CO_2 storage were limited, cement applications would dominate the overall deployment of industrial capture and CO_2 utilisation would increase.

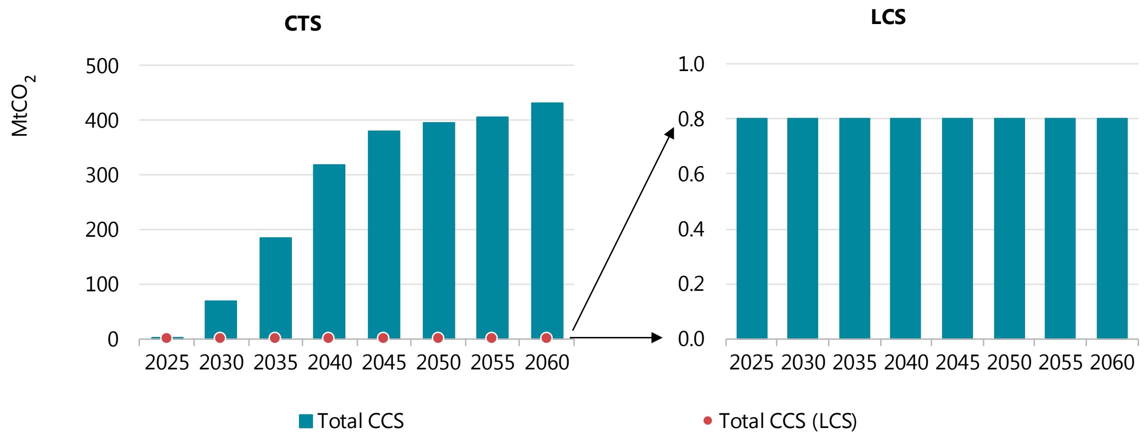
A closer look at the iron and steel sector

Iron and steel production consumes approximately 35 EJ of final energy and releases 2 Gt CO_2 direct emissions annually, representing a major industrial CO_2 source. Crude steel can be produced through primary routes, in which it is produced from virgin iron extracted from iron ores, or through secondary routes from recycled scrap. Primary production pathways consist of several combinations of technologies to produce iron and crude steel: blast furnace (BF) or smelting reduction followed by a basic oxygen furnace (BOF), or direct reduction followed by an electric arc furnace (EAF). The BF-BOF primary route consumes almost three times more energy per unit of crude steel on average than the scrap-based EAF path (World Steel, 2018a). The route based on the reduction of iron ore in blast furnaces, mainly with coke, is widely deployed accounting for 71% of crude steel production (World Steel, 2018b). Coal represents, therefore, almost 80% of the final energy used in the iron and steel sector.

Improving energy and material efficiency, switching to alternative fuels and deploying innovative process technologies are the main CO_2 mitigation levers supporting the sustainable transition of iron and steel making. Strategies such as improving manufacturing yields to reduce material losses, promoting the reuse of steel components into new products, extending the lifetime of buildings and incentivising lightweighting of vehicles contribute to reducing the demand for crude steel by about 15% cumulatively in the CTS compared to the RTS by 2060, resulting in around 6 Gt CO_2 savings. At the same time, increasing collection and recycling rates increases the flow of scrap back to the manufacturing sites, which enables a greater uptake of secondary crude steel production. Scrap use for crude steel production increases by 12% in 2060 in the CTS compared to the RTS, with scrap-based EAF growing its share of total liquid steel production by 20 percentage points in that year.

Energy efficiency improvements and deploying best available technologies contribute around 60% of the cumulative emissions reductions in the CTS by 2060 relative to the RTS. While natural gas-based direct reduced iron (DRI) increases its share of total DRI production by 15 percentage points in the CTS compared to the RTS in 2060 (reaching 96%), total DRI production falls in absolute and relative liquid steel terms in the CTS that year. This is the result of a combination of new upgraded coal-based processes that facilitate the integration of carbon capture being found more competitive, and natural gas prices being less advantageous relative to coal prices in certain regions. The integration of CCS in iron and steel manufacturing accounts for 8 Gt CO_2 of reductions from the RTS cumulatively by 2060 (with 10 Gt CO_2 captured and stored in the CTS, compared to 2 Gt CO_2 in the RTS), reaching 44% of the total generated emissions in the sector that year. CO_2 capture from natural gas-based DRI for EOR has already been commercially proven in United Arab Emirates, where a capture plant has been operative since 2016, with a capacity of 0.8 Mt CO_2 captured and stored per year.

Figure 29. Annual captured CO_2 for storage in the iron and steel sector in the CTS and LCS



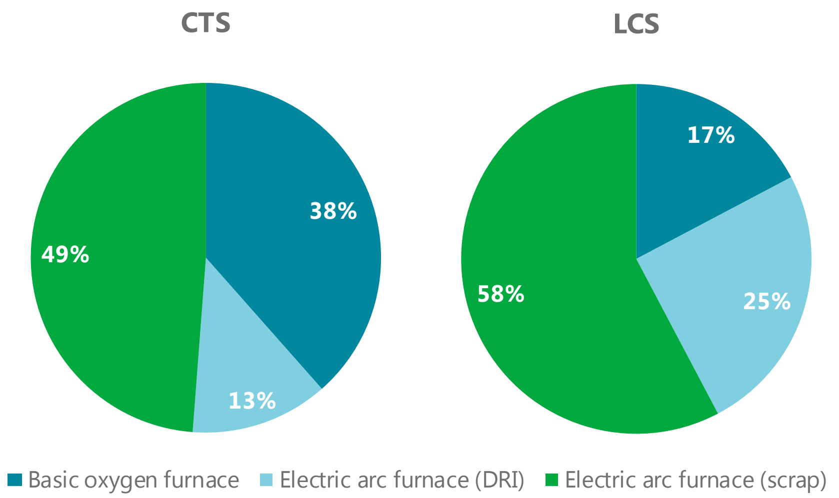
Note: Analysis above uses the Energy Technology Perspectives modelling framework.

The limited CO_2 storage context considers that no further CCS would be deployed beyond the already existing 0.8 Mt CO_2 annual capture capacity at a natural gas-based DRI plant.

If availability of CO_2 storage were limited as in the LCS, strategies such as material efficiency and alternative routes that facilitate greater integration of low-carbon electricity – directly or through electrolytic hydrogen – would become more important. The deployment of CCS in iron and steel making would be severely reduced in the LCS compared to the CTS, so that no additional capture capacity for storage would be installed beyond the existing levels (Figure 29).

Scrap collection rates for recycling increase by 15% by 2060 in the CTS, reaching 91% globally on average across the different demand segments (e.g. buildings, vehicles, domestic appliances, industrial equipment). In the LCS, maximising the use of recovered scrap would become even more critical. The share of scrap-based EAF production would increase by about 9 percentage points in 2060 compared to the CTS (Figure 30). Material yields to produce steel components such as bars, plates, coils and casted products currently range between 70% and 100%, and this range is reduced to 80–100% in the CTS by 2060. Material losses produced in the manufacture of steel parts used in buildings, vehicles and domestic appliances, among others, are also reduced by around 50% on average across the different demand segments, resulting in 8% loss of material input on average in the CTS in 2060. These considerable efforts leave limited room for further improvement in reducing material losses in manufacturing in the LCS. Further material demand reductions could be obtained by expanding work on material efficiency strategies at the different stages of specific value chains beyond the manufacturing phases.

Figure 30. Liquid steel production by process route in 2060 in the CTS and LCS



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

DRI- and scrap-based routes would increase at the expense of primary BOF production if CO_2 storage were limited.

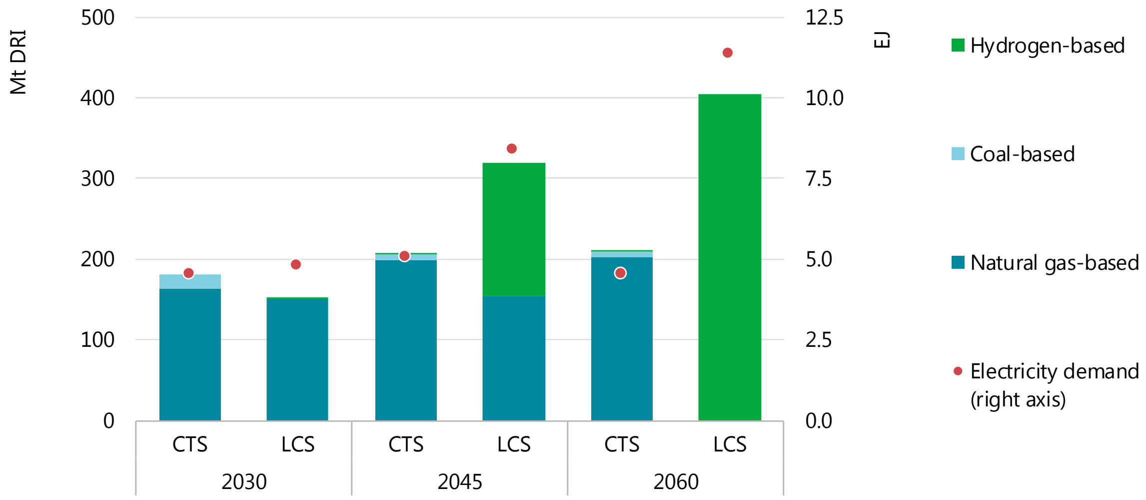
Alternative iron making processes to conventional primary production routes based on coal or natural gas are being developed with firm plans for demonstration, particularly in Europe. In Sweden the reduction of iron ore directly through electrolytic hydrogen is being investigated to replace reduction through synthetic gas produced from natural gas in a DRI process. This innovative process is at technology readiness level (TRL) 5, with the objective of starting pilot trials in 2021 and completing commercial demonstration by 2035. On the basis that renewable electricity is used to produce the required hydrogen and the thermal energy needed (from the iron ore agglomeration step to liquid steel production) relies on bioenergy, this process would drastically reduce the CO_2 footprint of crude steel making by 98% (Hybrit, 2017).

Further opportunities are being explored to integrate low-carbon electricity directly in iron and steel making. For example, the direct use of electricity to reduce iron oxides is being researched by different projects at TRL 4, with the objective of developing certain process components and pilots in 2022–24, but with no specific targets for commercialisation. Two main R&D streams are investigating this production route: aqueous alkaline electrolysis at around 110°C being researched in Europe, and a molten oxide electrolysis process operating at above 1 500°C being developed in the United States.

If the availability of CO_2 storage were limited, hydrogen-based DRI would be more widely deployed at the expense of fossil fuel-based DRI, but also of other primary production routes. By 2045 hydrogen-based DRI would already account for about half of total DRI production and dominate that production route by 2060 in the LCS (Figure 31). As a result of this technological shift, the demand for electricity for iron and steel making would more than double in 2060 in the LCS relative to the CTS, reaching around 11 EJ in that year or about 20% of total industrial electricity demand by then. The greatest contributor to the additional demand for electricity would be operating the electrolyser capacity to produce the required hydrogen for this route, in addition to the electricity needed for the additional DRI and EAF capacity.

Iron oxide electrolysis processes would not be deployed in the LCS to a significant degree within the analysed time period, as hydrogen-based DRI reaches commercialisation earlier (by 2035 according to announced targets). Its deployment would ramp up from 2040 onwards relatively quickly, leaving limited room for another low-carbon electricity-based process to compete in the later period of the modelling horizon. In practice, direct reduction of iron oxides with electricity might play a complementary role with hydrogen-based DRI in the long-term, in contexts with limited availability of CO_2 storage. It is critical to continue monitoring the progress of the relevant RD&D streams to reduce the uncertainty around the performance and commercial availability of these innovative processes.

Figure 31. Production of DRI and electricity demand in steel making in the CTS and LCS



Notes: Electricity demand shown refers to the electricity demand related to all production routes for iron and steel making. Analysis above uses the Energy Technology Perspectives modelling framework.

Hydrogen-based DRI would dominate DRI production in 2060 in the LCS, more than doubling demand for electricity in the sector.

A closer look at the cement sector

The manufacturing of cement consumes 11 EJ of final energy and releases 2.2 Gt CO_2 direct emissions annually, representing a major industrial CO_2 source. Cement manufacture involves the decomposition of limestone (calcium carbonate) when producing clinker,[8] which represents about two-thirds of the total CO_2 emissions generated in the process, with the remainder being due to combustion of fuels. More than 95% of the thermal energy used to produce cement is based on fossil fuels, of which coal accounts for about 70%.

Improving energy and material efficiency, switching to alternative fuels (such as biomass or waste), reducing the clinker to cement ratio and deploying innovative technologies and products are the main CO_2 mitigation levers supporting the sustainable transition of the cement sector. As a result of a suite of material efficiency strategies, particularly the extension of the lifetime of buildings through supported energy efficiency retrofits, the demand for cement is reduced by 15% in the CTS in 2060 compared to the RTS. This translates into cumulative savings of around 6.5 Gt CO_2 by 2060. The reduction of the clinker to cement ratio and the integration of carbon capture in cement production are other key strategies, both mitigating energy-related and process CO_2 emissions, accounting for around 30% and almost 20% of the cumulative reductions, respectively, by 2060 in the CTS relative to the RTS. Cumulatively 5 Gt CO_2 are captured and stored by 2060 globally in the CTS, with stored CO_2 from cement production reaching 20% of the total emissions generated in the sector by that year.

If CO_2 storage were limited as in the LCS, and considering the same biomass supply as in the CTS, accelerating the reduction in the clinker to cement ratio and deploying alternative binding materials would become more important. It is unlikely, however, that direct CO_2 emissions could be decoupled from cement production without CO_2 storage. Blended cements with lower clinker to cement ratios generate less CO_2 emissions when manufactured, but typically rely on industrial by-products as cement constituents, such as ground granulated blast furnace slag and fly ash, which are expected to be less available in the CTS. This effect would be widened further in a context of limited CO_2 storage, as the shift away from coal-based power generation would be accelerated and there would be increasing pressure to reduce primary steel production. Cements with low clinker to cement ratios that are based on widely available raw materials such as calcined clay and ground limestone (recent cement mix developments), as well as using limestone as a filler (currently in commercial use), can contribute to reducing the clinker to cement ratio. This is already the case in the CTS, enabling the ratio to fall to 60% by 2060 globally on average, despite the increasingly limited availability of conventional clinker substitutes.

Alternative cement binding materials that rely on different raw materials or material mixes compared to Portland cement (PC)[9] clinker are either commercial or are being tested and developed to mitigate the environmental impact of process CO_2 emissions. The alternative materials, in principle, offer opportunities for carbon emissions reductions, but their commercial availability and market applicability differ widely. Some binding material families also rely on industrial by-products (e.g. alkali-activated materials or geopolymers) or compete for raw materials with other industrial sectors, which does not solve the long-term availability

[8] An intermediate product in cement manufacturing and the main substance in cement. It is the result of calcination of limestone in the kiln and subsequent reactions caused through burning.
[9] PC is the most common type of cement, consisting of over 90% clinker and about 5% gypsum.

problem and raises production costs due to heightened competition for these resources. (See Box 5 for additional information on alternative binding materials.)

By 2060 the cumulative deployment of CCS would be 15% lower in the LCS compared to the CTS, reaching 4 Gt CO_2, but would still play a determining role in the overall emissions reduction effort. In this variant, captured emissions for storage would reach similar levels of deployment by 2060 compared to the CTS: 18% of the total direct emissions generated in cement production compared to 20% in the CTS. (See Table 1 for a summary of these and other sustainability indicators for cement by scenario.)

Table 1. Key sustainability indicators of cement production by scenario

2060	RTS	CTS	LCS
Cement production (Mt)	4 559	3 879	3 879
Thermal energy intensity* (GJ/t clinker)	3.1	3.9	3.9
Electricity intensity(kWh/t cement)	88	95	94
Thermal share of alternative fuels (%)	18%	31%	31%
Clinker to cement ratio	0.66	0.59	0.59
CO_2 captured and stored (Mt CO_2)	221	377	347
Direct CO_2 intensity of cement (tCO_2/t cement)	0.5	0.4	0.4

Notes: Thermal energy intensity of clinker and electricity intensity of cement include impacts related to other carbon mitigation levers beyond improving energy efficiency (e.g. additional energy demand to operate carbon capture equipment). Electricity intensity of cement production does not include reduction in purchased electricity demand from the use of waste heat recovery equipment. Alternative fuel use includes biomass, and biogenic and non-biogenic waste. Direct CO_2 intensity refers to net CO_2 emissions, after carbon capture. GJ/t = gigajoule per tonne; kWh/t =kilowatt hour per tonne; t = tonne.

Box 5. Alternative binding materials for cements

There are different families of alternative cement binding materials that rely on different raw material mixes or different raw materials compared to PC, and which are currently at different stages of development:

Belite clinker contains no or little alite and between 40% and 90% belite, leading to about a 6% reduction in the process CO_2 intensity of clinker. China has been producing belite cements over the past 15 years, with the first successful application for dam construction in the third phase (2003–09) of the Three Gorges Hydropower Project.

Calcium sulphoaluminate (CSA) clinker contains ye'elimite as the main constituent, which directly reduces process CO_2 emissions. For instance, a commercial CSA clinker yields a 44% reduction in the process CO_2 intensity of clinker compared to PC clinker. They have been commercially produced for more than 30 years, primarily in China.

Alkali-activated binders (sometimes called geo-polymers) are produced by the reaction of an alumino-silicate (the precursor) with an alkali activator. They can reduce CO_2 emissions depending on the carbon emissions associated with the production of alkali activators.

Belite calcium sulphoaluminate (BCSA) clinker is being investigated to circumvent the high raw material costs of CSA clinkers by increasing the proportion of belite and adding alumino-ferrite to CSA clinkers, thus delivering a clinker process CO_2 intensity 20–30% lower than that of PC. They are not commercially produced yet, and specific norms for this type of clinkers do not currently exist, with the exception of those BCSA clinker compositions that are within Chinese norms for CSA clinkers.

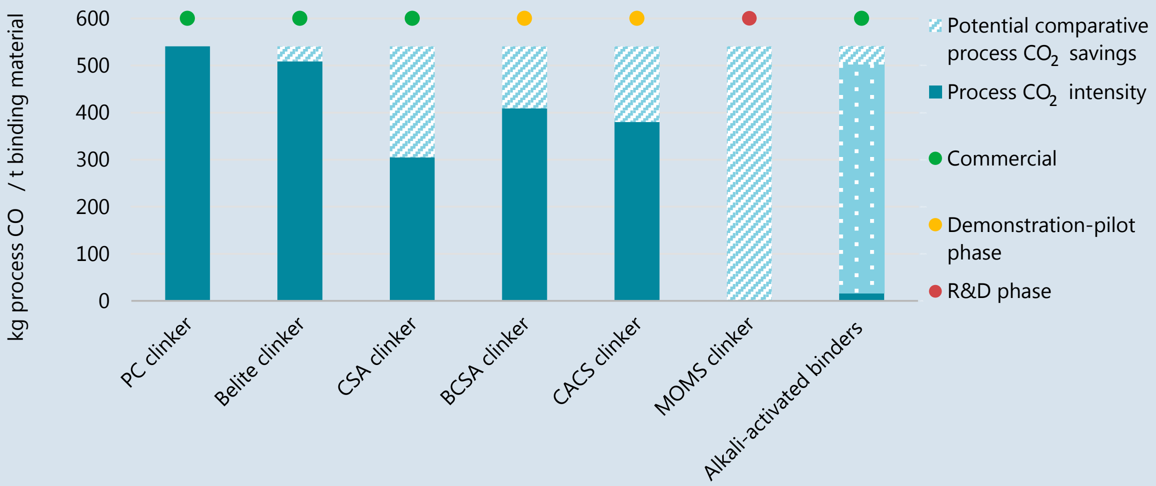
Cements based on **carbonation of calcium silicates (CACS)** can sequester CO_2 as they cure. Therefore, even if they are based on similar raw materials to PC clinker, these types of cement can yield zero process CO_2 emissions in net terms. Such a CACS clinker is being developed by a single private venture, and its use is limited to local technical approval.

The manufacture of cement based on **prehydrated calcium silicates (PHCS)** is beneficial because these materials can be easily produced at low temperatures and under pressure controlled conditions. A pilot project was completed in 2017 and a first industrial-scale demonstration is planned.

Cements based on **magnesium oxides derived from magnesium silicates (MOMS)** are, in principle, able to counterbalance or even absorb more CO_2 than the amount released in the manufacturing process while curing. Currently no industrial-scale optimised process has been developed. The main unresolved issue is the production at industrial scale of magnesium oxides from basic magnesium silicates with acceptable energy efficiency levels.

Barriers exist to the wider market deployment of alternative binding materials compared to PC clinker. These are related to technology and raw material costs, technical performance, range of possible market applications and level of standardisation for such materials.

Process CO_2 emissions intensity for selected cement binding materials



Notes: kg = kilogram. PC clinker mainly contains 63% alite, 15% belite, 8% tricalcium aluminate and 9% tetracalcium alumino-ferrite. Belite clinker mainly contains 62% belite, 16% alite, 8% tricalcium aluminate and 9% tetracalcium alumino-ferrite. CSA clinker mainly contains 47.5% ye'elimite, 23.9% belite, 12.9% wollastonite and 8.6% tetracalcium alumino-ferrite. BCSA clinker mainly contains 46% belite, 35% ye'elimite and 17% tetracalcium alumino-ferrite. Commercial compositions of CACS clinker are not currently available. The CACS clinker in this assessment is considered to primarily consist of wollastonite, but commercial composition is likely to be different, and possibly higher in process CO_2 emissions. Process CO_2 emissions generated in CACS clinker making are, in principle, re-absorbed during the curing process. MOMS are considered to be sourced from magnesium silicate rocks. Given the wide range of mix designs, sources and doses, it is not possible to provide a single value or even a well-defined range to describe the CO_2 footprint of alkali-activated binders. The figure above shows two possible extreme examples ranging from 97% to 10% CO_2 savings compared to PC.

Sources: Quillin (2010), Calcium Sulfoaluminate Cements: CO_2 Reduction, Concrete Properties and Applications; UNEP (2016), Eco-efficient Cements: Potential, Economically Viable Solutions for a Low-CO_2, Cement-based Materials Industry; Gartner and Sui (2017), "Alternative cement clinkers".

A closer look at the chemical sector

The chemical and petrochemical sector[10] consumes about 45 EJ of final energy, of which 22 EJ are feedstock-related, and releases around 1.5 Gt CO_2 direct emissions annually, representing the third-largest industrial source of CO_2. The energy used as feedstock constitutes the sector's raw material input and most of the carbon becomes embedded in chemical products, thus avoiding the release of CO_2 provided the products are not oxidised during use or disposal. Oil and natural gas account for almost 70% of the total energy consumed in the chemical sector, with oil alone accounting for 45%. Seven chemicals (called primary chemicals) account for around two-thirds of the total energy consumption in the sector, namely: ethylene, propylene, benzene, toluene, mixed xylenes, ammonia and methanol. Ammonia accounts for around 30% of the total direct CO_2 emissions from the sector, followed by high-value chemicals[11] at around 16% and methanol at 15%.

Increased levels of energy and material efficiency, switching to alternative feedstocks and energy carriers that are less carbon-intensive, and the integration of CCUS are the main mitigation strategies pursued in the chemical sector. Plastic waste recycling, the reuse of plastic products and increased efficiency in the application of fertilisers are examples of material efficiency strategies that can result in primary chemical savings. Plastic recycling[12] and reuse, for instance, reduce the demand for primary chemicals in the CTS by 6% cumulatively compared to the RTS, equating to approximately 3 Gt CO_2 cumulative savings by 2060. Energy efficiency, supported by process integration measures and the wider deployment of catalytic processes, together with a shift towards natural gas and alternative feedstocks, provide almost 50% of the total CO_2 emissions reductions by 2060 in the CTS relative to the RTS. Cumulatively, 6 Gt CO_2 are captured for storage in the chemical sector by 2060 in the CTS, with the capture rate in 2060 equating to around 25% of the total emissions generated in the sector annually. The integration of carbon capture is a cost-effective strategy to deliver significant reductions of CO_2 emissions compared with other options, particularly in those processes where CO_2 is already inherently separated and/or that produce concentrated CO_2 streams. Ammonia production is one such example: about 75% of the cumulative CO_2 stored in the chemicals sector in the CTS is captured from ammonia production.

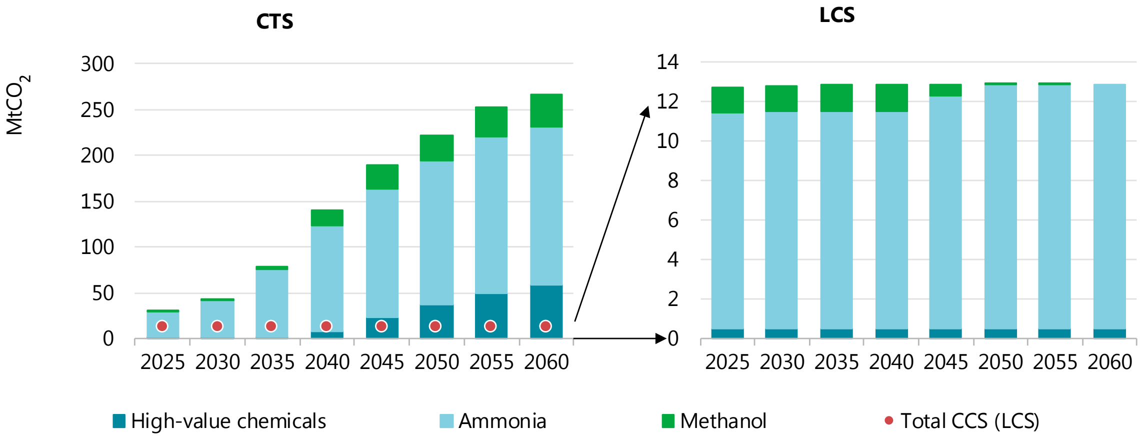
If CO_2 storage were limited as in the LCS, and when considering the same biomass availability as in the CTS, strategies such as material efficiency and utilising alternative feedstocks (including electrolytic hydrogen) would become more important. CCS in the chemical sector would be reduced by more than 90% cumulatively by 2060, relative to the CTS (Figure 32). About 90% of this stored CO_2 would be captured in ammonia production, further emphasising the role of ammonia in reducing emissions.

[10] Referred to as the chemical sector hereafter.

[11] High-value chemicals refer to ethylene, propylene, benzene, toluene and mixed xylenes.

[12] Plastic recycling is assessed for the main thermoplastic resins: polyethylene terephthalate, high-density polyethylene, polyvinyl chloride, polypropylene, polystyrene and an aggregated selection of other thermoplastics, such as: acrylonitrile butadiene styrene, styrene acrylonitrile, polycarbonate and polymethyl methacrylate. For more information on the impacts of plastic waste recycling, please refer to IEA (2018).

Figure 32. Captured CO_2 for storage in the chemical sector in the CTS and LCS



Notes: High-value chemicals refers to ethylene, propylene, benzene, toluene and mixed xylenes. Analysis above uses the Energy Technology Perspectives modelling framework.

If CO_2 storage were limited, most of the capture applications in the chemical sector would be concentrated in ammonia production.

Plastic waste collection rates for recycling more than triple by 2060 in the CTS, increasing to around 50% average collection rates globally from 14% in 2015. Recycling yields and displacement rates[13] also improve at a good pace, building on the basis that significant technical advances in recycling processes materialise over the period analysed. The uptake of plastic recycling in the CTS therefore leaves limited room for further development in a limited CO_2 storage context.

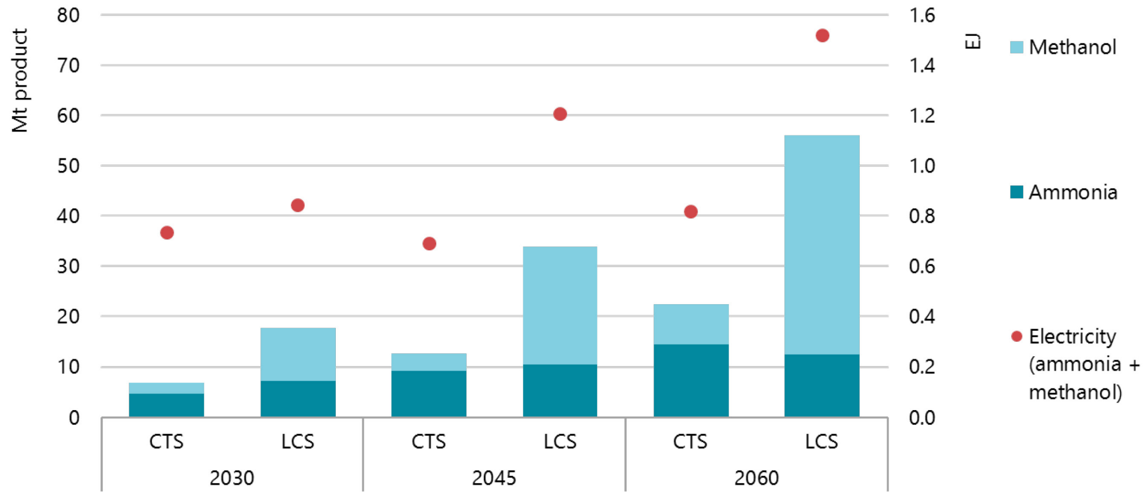
New processes to produce ammonia and methanol through hydrogen from water electrolysis and CO_2 (in the case of methanol) are currently at TRL 7 (Bazzanella and Ausfelder, 2017). The required individual technologies are, in principle, available and system integration should be relatively straightforward. However, the production of ammonia from hydrogen based on water electrolysis has not reached commercial stage. Plans have been announced to build a solar-powered ammonia demonstration plant, to be commissioned in 2019 in Australia by Yara, the world's largest ammonia producer (Brown, 2017). The hydrogenation of pure CO_2 to methanol with hydrogen from water electrolysis is possible though commercially available catalysts. A number of pilots are in operation to prove the possibilities for industrial-scale production (Bazzanella and Ausfelder, 2017).

Limiting CO_2 storage would result in a combined increase of 2.5 times in ammonia and methanol production using electrolysis by 2060, relative to the CTS (Figure 33). As a result, electricity demand for these two chemicals would nearly double in 2060 in the LCS relative to

[13] The recycling yield rate accounts for the material losses incurred during the preprocessing and recycling processes. The displacement rate refers to the amounts of plastic resins and products that, when recycled, are remanufactured into forms that either do not fulfil their original purpose, or prevent the material from being recycled again, or both.

the CTS. Operating approaches and technologies that can contribute to more flexible electricity demand would be even more valued in the limited CO_2 storage context, in which electricity would be a commodity in high demand.

Figure 33. Electrolytic hydrogen-based ammonia and methanol production in the CTS and LCS



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

If CO_2 storage were limited, electrolytic hydrogen routes for ammonia and methanol production would be significantly increased, pushing upwards the electricity demand for these products.

Increased methanol production based on electrolytic hydrogen in the limited storage variant would indirectly raise the need to identify carbon sources that complement the required feedstock mix in the process. This would result in CO_2 capture for utilisation as feedstock for methanol production increasing almost fivefold by 2060 relative to the CTS, reaching 60 Mt CO_2 (equivalent to 8% of total direct emissions from chemical production in the same year). The iron and steel sector generates several gases (works arising gases) containing valuable components that make them suitable for use as fuels, reducing agents or even feedstock. For instance, about 20% of the methanol produced in China today uses coke oven gas as feedstock, which contains mainly hydrogen, methane, carbon monoxide and CO_2. The Carbon2Chem project in Europe aims to demonstrate ways to convert works arising gases into ammonia and methanol, with production rates fluctuating to support electricity grid balancing needs (Thyssenkrupp, 2017).

Box 6. Cost-competitiveness of alternative production routes: ammonia in the spotlight

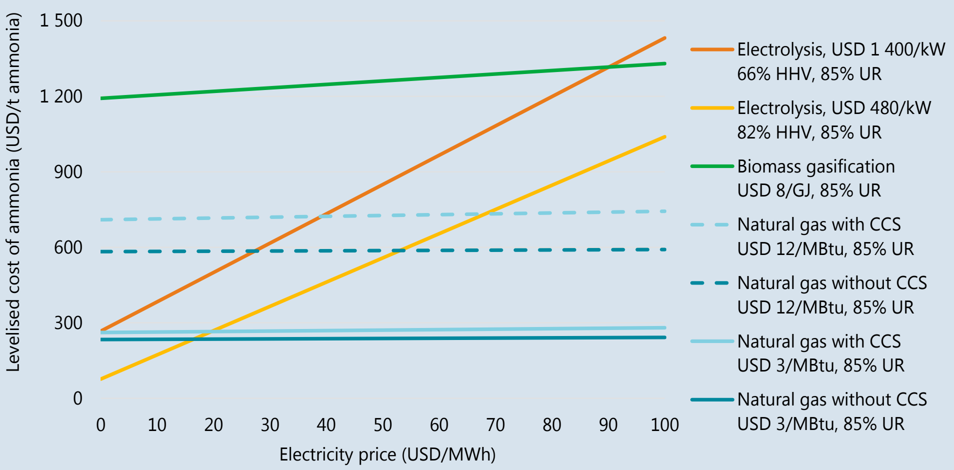
Various options are available to drastically reduce CO_2 emissions from ammonia production: fossil-based routes equipped with CCS; the use of electrolytic hydrogen based on low-carbon electricity as feedstock; and bioenergy-based processes. These routes compete on a least-cost basis in the underlying analysis of the different scenarios in this report. Energy prices, capital expenditure (CAPEX) and utilisation rates are sensitive variables, and so routes are assessed across a range of values for these parameters.

The bioenergy-based process for ammonia production is competitive with the electricity pathway only in a very limited set of circumstances, namely when electricity prices are high (more than USD 90/megawatt hour [MWh]) and biomass prices are low (around USD 8/gigajoule [GJ]). Utilisation rates must also be high, as must be the CAPEX requirements for electrolysers.

The electrolytic hydrogen pathway is highly sensitive to CAPEX at low utilisation rates, whereas at higher utilisation rates it is also sensitive to electricity prices. Given a middling natural gas price of USD 7 per million British thermal units (MBtu) (typical of prices in Europe today, but significantly higher than in the United States and the Middle East), electrolysis starts to compete with gas-based production equipped with CCS at low electricity prices of USD 20–45/MWh, depending on electrolyser efficiency and CAPEX levels. This assumes that both energy-related (lower CO_2 concentrations) and process emissions (higher CO_2 concentrations) from ammonia production are captured. If only the concentrated process emissions are to be captured (and the ammonia is therefore only partly decarbonised), electricity prices must be below USD 20/MWh for the electricity pathway to compete. At upper range natural gas prices (USD 12/MBtu) with total emissions capture, electrolysis begins to compete at higher electricity prices of around USD 40-70/MWh.

Dedicated renewable electricity generation for ammonia production at locations with important renewable resources could be an alternative to achieve low-cost electricity and high full load hours (see Box 7 for further information). In places where this coincides with the availability of viable CO_2 storage options, fossil-based ammonia production equipped with CCS and electrolytic hydrogen-based production would directly compete.

Simplified levelised cost of ammonia for various pathways



Notes: Energy cost assumptions: USD 3–12/MBtu for natural gas; USD 8–18/GJ for biomass; USD 30–90/MWh for electricity. CAPEX assumptions: USD 860/t of ammonia for natural gas steam reforming; USD 50–270/t captured CO_2 for carbon capture, with the range encompassing both concentrated (process CO_2) and dilute (energy-related CO_2) sources and a 90% capture rate applied to each source; USD 6 000/t ammonia for biomass gasification; USD 9/t nitrogen for air separation unit; USD 95/t ammonia for air separation unit; USD 480–1 400 per kilowatt electrical capacity (kW_e) for electrolysis. CAPEX assumptions stated per unit of output, apart from electrolysis which is stated per unit of electricity input. Fixed operational expenditure = 2.5–5.0% of CAPEX. Electrolyser efficiency = 66–82% on a higher heating value (HHV) basis. Energy performance of an average ammonia plant. Storage and transport costs as USD 20/t captured CO_2. Discount rate = 8%. A 25-year design life is assumed for all equipment. UR = utilisation rate.

Source: Analysis above based on IEA (2018), *The Future of Petrochemicals*.

Given a middling natural gas price of USD 7/MBtu, electrolysis starts to compete with gas-based production equipped with CCS at electricity prices of around USD 20-45/MWh, depending on electrolyser efficiency and cost.

In-depth analysis: Implications for the fuel transformation sector in the LCS

In the LCS, CO_2 storage in the fuel transformation and power sectors between 2017 and 2060 would be limited to around 5 Gt CO_2, or 6% of the CO_2 being cumulatively stored in the CTS in power generation and fuel transformation combined. As a consequence, only 4.4 Gt CO_2 would be cumulatively stored in the fuel transformation sector, compared to 31 Gt CO_2 in the CTS (Figure 34). This does not mean, however, that the cumulative CO_2 emissions of the fuel transformation sector in the LCS would increase by the difference in the CO_2 amounts stored. Instead of storing CO_2, the captured CO_2 could also be used, though the marginal abatement costs for the CO_2 usage options considered in the fuel transformation sector are in most cases higher than storing the CO_2. This explains that, if CO_2 storage is available as in the CTS, CCU plays only a small role in the fuel transformation sector.

A CCU option that would be highly utilised in the LCS is the use of CO_2 in combination with hydrogen from low-carbon electricity to produce synthetic liquid or gaseous hydrocarbon fuels, also referred to as power-to-liquids (PtL) or power-to-gas (PtG) fuels. These synthetic fuels then could substitute the use of fossil fuels in other parts of the energy system, especially those sectors that are hard to decarbonise otherwise. CCU pathways producing PtL or PtG fuels can – under certain conditions through the substitution of fossil fuels – provide CO_2 reductions similar to the ones that would be achieved by geologically storing the CO_2 instead, as also explained later in the section "CCU options in the fuel transformation sector". In the LCS, the production of PtL and PtG fuels would result in cumulative CO_2 reductions of 5 Gt CO_2 in the fuel transformation sector, relative to the CTS, of which 4.2 Gt CO_2 would be achieved through bioenergy with carbon capture and use (BECCU), i.e. here the production of PtL or PtG fuels from CO_2 captured at biomass power plants or biofuel production plants (Figure 34).

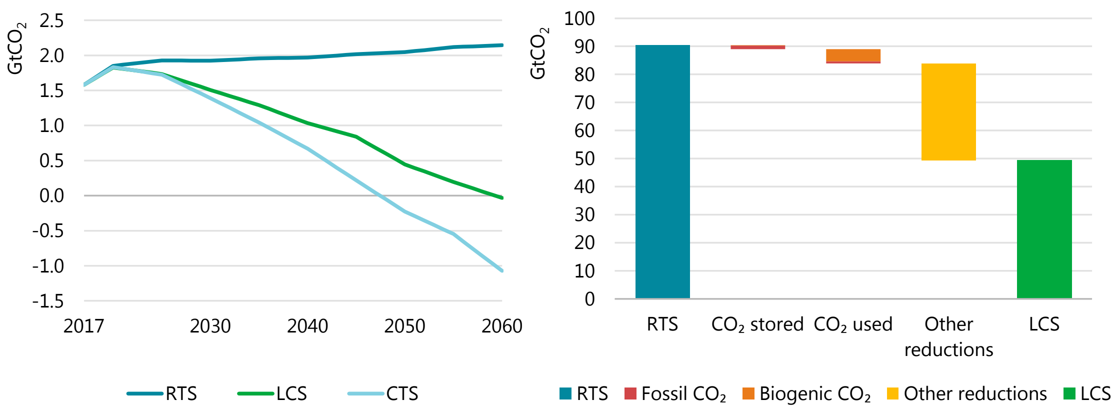
BECCU could become an alternative to BECCS in the absence of CO_2 storage as it can result in very similar CO_2 reductions, as discussed in the following section on CCU. In total, however, CCU in the form of PtL and PtG would contribute only 1% of the cumulative CO_2 reductions relative to the RTS, a contribution much smaller than the 4% CCS in fuel transformation provides in the CTS. This reflects the higher mitigation costs of these CCU options compared to CCS, especially due to the additional electricity required for the synthetic hydrocarbon options from electrolytic hydrogen.[14]

Relative to the CTS, the fuel transformation sector's cumulative CO_2 emissions would increase by 17 Gt CO_2 if CO_2 storage were limited. The sector's annual CO_2 emissions in 2060 in the LCS

[14] In the LCS, the marginal avoidance costs of the CCU option PtL is in the range USD 300-450/tCO_2 in 2060, depending on the costs and full load hours of electricity, whereas the storage costs for CO_2 in CCS are USD 5-25/tCO_2.

would be 1 040 Mt CO_2 higher than in the CTS. The sector would still reach net negative emission levels in 2060 in the LCS, but at a much lower level than in the CTS, i.e. -0.03 Gt CO_2 compared to -1.1 Gt CO_2.[15]

Figure 34. Annual CO_2 emissions of global fuel transformation sector and cumulative CO_2 reductions in the LCS



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

CCUS would account for a sixth of the cumulative CO_2 reductions in the fuel transformation sector in the LCS relative to the RTS, largely from CO_2 usage.

CCU options in the fuel transformation sector

CCU in the form of using the captured CO_2 in combination with hydrogen to produce a synthetic hydrocarbon fuel can be an alternative to storing the CO_2, although if CO_2 storage is available, CCU is often a more expensive option than CCS. Three power-to-fuels synthesis routes have been considered as CCU options in the fuel transformation sector. Two methods for creating PtL fuels have been modelled: the production of synthetic diesel or kerosene via Fischer-Tropsch synthesis, and hydrogen-enhanced biofuel production for gasoline via methanol. One PtG option, the production of synthetic natural gas (SNG) via chemical methanation, has been included in the analysis.[16]

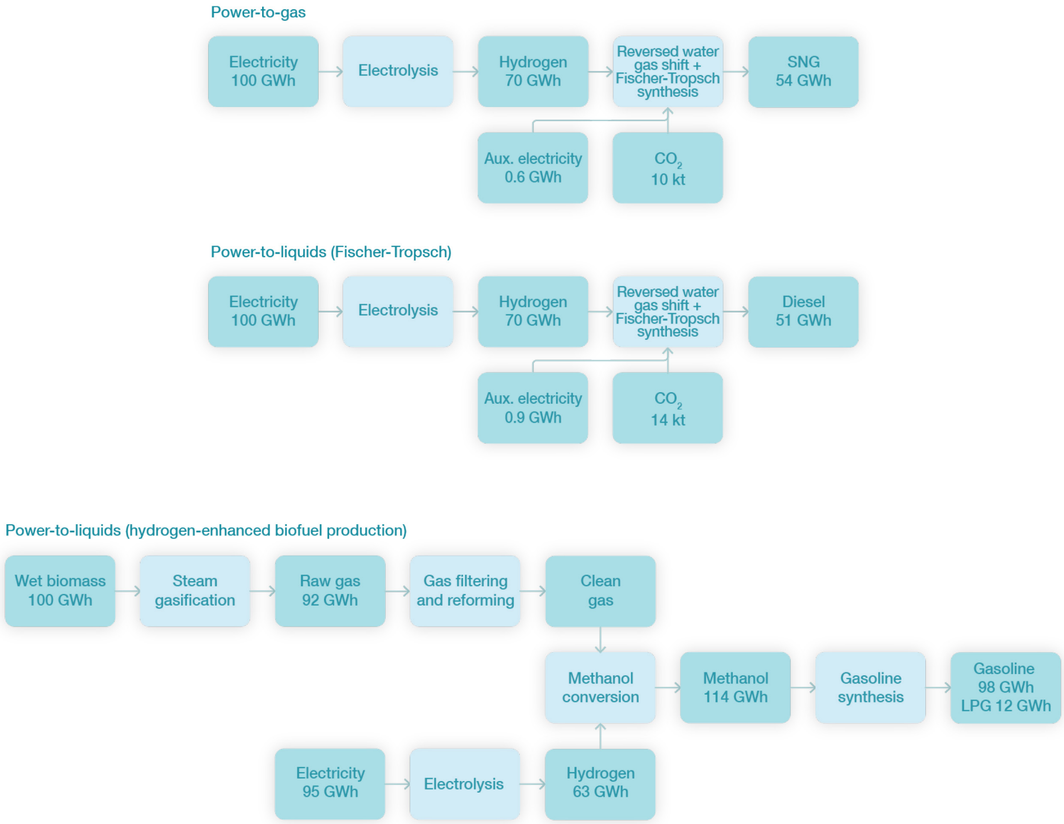
Power-to-liquids: The main synthesis steps for the production of synthetic diesel or kerosene are (a) the electrolysis of water to hydrogen, then (b) chemical fuel synthesis consisting of the

[15] The negative emission levels of the fuel transformation sector in the LCS would not be caused by BECCS, but refer to CO_2 reductions from substituting fossil fuels in the end-use sectors with PtL or PtG fuels, produced from biogenic CO_2. Due to the use of biogenic CO_2, these synthetic fuels are similar to biofuels, i.e. when burnt they do not contribute to the anthropogenic CO_2 emissions. These CO_2 reductions from substituting fossil fuels have currently been accounted for in the fuel transformation sector and not the end-use sectors. If the remaining fossil fuel-related CO_2 emissions in the fuel transformation sector are lower than the CO_2 reduction from biogenic synfuels, this creates negative emission levels in the CO_2 accounting.

[16] Further PtL pathways exist, in particular for the production of chemical feedstocks such as methanol or dimethyl ether. They are not included here, but instead discussed in the context of the industry sector (see previous section). Further technology pathways, though not explicitly considered in this version of the LCS, also exist for the use of hydrogen for upgrading the biogas from anaerobic biogas digestion or from biomass gasification. In both pathways, hydrogen can be used to convert otherwise emitted CO_2 into methane, thus increasing the overall conversion efficiency of the processes.

reversed water gas shift reaction to convert CO_2 with hydrogen into CO (and water), followed by the Fischer-Tropsch (FT) reaction to convert hydrogen and CO into the synthetic fuels (Figure 35). The theoretical maximum conversion efficiency of hydrogen to fuel in energy terms (lower heating value [LHV]) is 83%, with losses in the synthesis process and in product upgrading yielding efficiencies of 77%. Taking into account the electrolysis step, the overall conversion efficiency of electricity to fuel is around 57%.

Figure 35. Technology pathways for PtL and PtG considered in the analysis



Notes: Aux. = auxiliary; GWh = gigawatt hour; kt = thousand tonnes; LPG = liquefied petroleum gas.

Sources: FCHJU (2014), "Study on development of water electrolysis in the EU"; Hannula (2016a), "Hydrogen enhancement potential of synthetic biofuels manufacture in the European context: A techno-economic assessment"; Tremel et al. (2015), "Techno-economic analysis for the synthesis of liquid and gaseous fuels based on hydrogen production via electrolysis"; Agora Verkehrswende, Agora Energiewende and Frontier Economics (2018), *The Future Cost of Electricity-Based Synthetic Fuels*.

Various PtL and PtG pathways exist to produce hydrocarbon fuels, with overall energy conversion efficiencies being around 50%.

The production cost of the PtL fuels depends on the investment costs (CAPEX), the cost of capital, the full load hours (FLH) of the equipment, and the cost of electricity and CO_2. The impact of CAPEX declines with increasing FLH (Figure 36 top). At 4 000 FLH, a doubling of the CAPEX increases the production cost by around a third. At these FLH ranges, electricity and CO_2 costs remain the most relevant cost factors. Electricity accounts for 60–75% of the production cost (at electricity costs of USD/MWh and 2 500-7 000 FLH). Providing electricity at low cost and high FLH is critical to bring down the cost of PtL fuels. Using dedicated renewable electricity from solar and wind at sites with excellent resource conditions – in some cases at remote sites far from large demand centres with shipping in of fuels being the only transport option – can be one way to realise low costs and high FLH (see Box 7). The CO_2 cost depends on the CO_2 capture cost (and possibly the cost of transporting CO_2 from the CO_2 source to the synfuel plant). High CO_2 concentrations in the flue gas stream lead to low capture costs – bioethanol production or second-generation biodiesel production via gasification are examples of such a processes.

When the CO_2 used for the production of the PtL fuel is of biogenic origin (i.e. from biomass) or captured directly from the air, burning the resulting PtL can be considered, similar to biofuels, as non-emitting of CO_2.[17] Burning these fuels can therefore be considered carbon-neutral, so that policy measures that penalise or restrict the use of fossil fuels, such as CO_2 prices or taxes, do not apply to PtL based on biogenic CO_2. This could provide PtL fuels based on biogenic sources with a possible cost benefit relative to fossil fuels. Based on the underlying techno-economic characteristics of production processes for PtL diesel (see footnotes of Figure 36), a CO_2 price increase of USD 100/tCO_2 leads to a cost increase of fossil diesel of USD 0.27/litre (or an equivalent relative cost benefit for biogenic PtL diesel). This allows biogenic PtL to be subject to an increase in electricity cost of USD 14/MWh and remain cost-competitive with fossil diesel (Figure 36 bottom).[18]

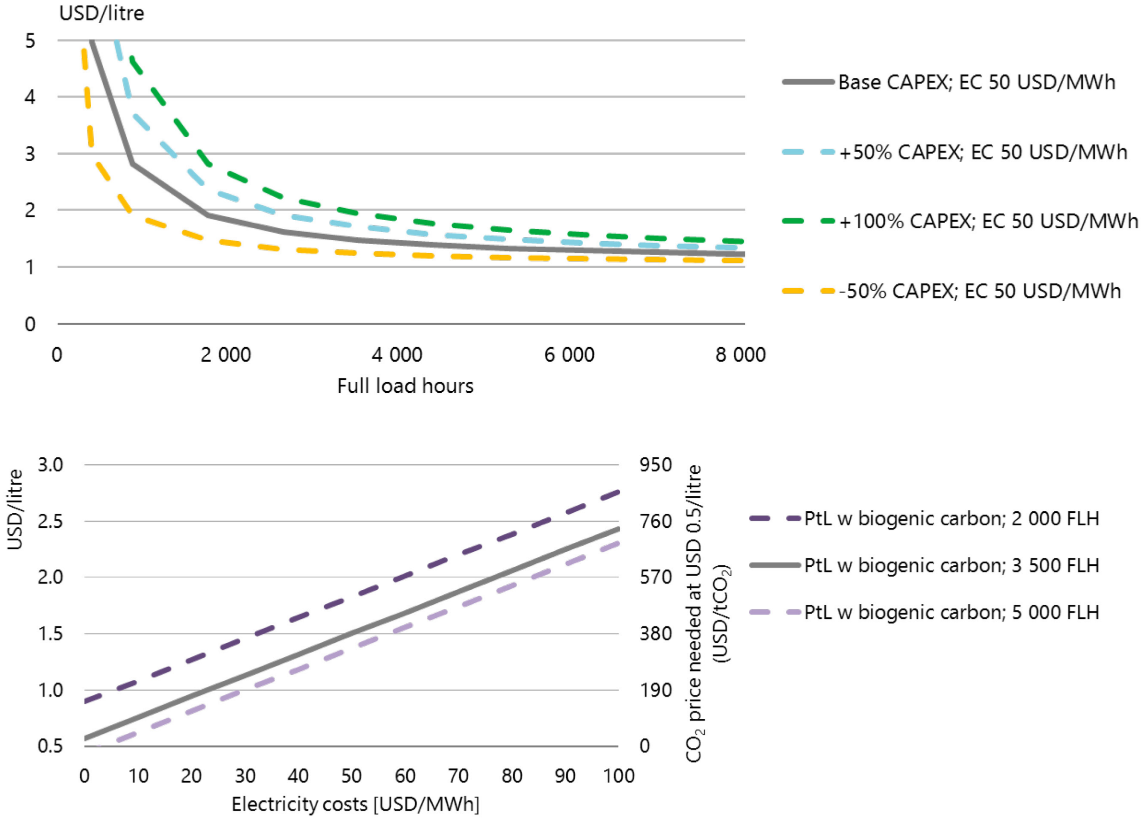
The use of hydrogen (H_2) from electrolysis to enhance gasification-based biofuel production processes is a further CCU option. Usually, the hydrogen to carbon monoxide (CO) ratio in the syngas is too low for the subsequent fuel synthesis process, so by adding steam in a water–gas shift reaction part of the CO is converted into hydrogen and CO_2, leading to higher H_2/CO ratio in the syngas (Hannula, 2016b). By providing additional hydrogen in place of steam, the conversion rate can also be increased so that instead of emitting part of the CO in the form of CO_2, all of it is converted into fuel in hydrogen-enhanced biofuel production (Figure 35).

The production of PtL fuels has been successfully demonstrated. In Dresden (Germany), a PtL plant with an electrolyser capacity of 150 kW_e has been producing 159 litres of syncrude per day since 2014, with CO_2 being provided by a biogas plant and through direct air capture. A larger PtL plant for methanol production has been operating in Iceland since 2012, with an electrolyser capacity of 6 megawatt electrical (MW_e) and a methanol output of 4 000 t per year. The required CO_2 is captured from the geothermal steam emissions of a geothermal power plant.

Power-to-gas: The PtG process route consists of water electrolysis to produce hydrogen and its synthesis together with CO_2 into SNG in the methanation process. The methanation can be biological or chemical. Biological methanation relies on microorganisms to convert hydrogen and CO_2 into methane in an anaerobic environment, while chemical synthesis converts CO_2 and H_2 into methane (CH_4) and water (H_2O) in a Sabatier reaction. Compared to chemical methanation, biological methanation is at an earlier development stage, with only a few pilot and demonstration plants being realised so far. Therefore, the chemical methanation pathway has been assumed in the model analyses here.

[17] This is based on the assumption that the released carbon will be reabsorbed by biomass regrowth, under balanced conditions.
[18] A carbon price or tax is used here in the cost analysis as a way to penalise the use of fossil fuels. This does not necessarily mean that a carbon price or tax will be the optimal policy instrument. In practice, alternative policy instruments leading implicitly to similar cost increases for the use of fossil fuels are possible, e.g. CO_2 intensity standards or renewable quotas for transport fuels.

Figure 36. Levelised production costs for PtL diesel as a function of the full load hours (top) and electricity costs (bottom)



Notes: Conv. = conventional; EC = electricity cost. CAPEX assumptions = USD 455/kW_e for electrolyser and USD 564/kW of PtL from conventional diesel; fixed operating and maintenance costs = 1.5% of CAPEX per year for electrolyser and 4% for FT synthesis; conversion efficiencies (LHV-based) = 74% for electrolyser (electricity to hydrogen) and 73% for FT synthesis (hydrogen to diesel); CO_2 feedstock costs = USD 30/tCO_2 (e.g. from bioethanol production); discount rate = 8%; technical lifetime = 30 years. Right axis of the bottom figure shows the CO_2 price needed to reach competitiveness with fossil diesel at USD 0.5/litre.

Sources: Brynolfa et al. (2018), "Electrofuels for the transport sector: A review of production costs"; FCHJU (2014), "Study on development of water electrolysis in the EU"; Schmid et al. (2018), "Future cost and performance of water electrolysis: An expert elicitation study"; Tremel et al. (2015), "Techno-economic analysis for the synthesis of liquid and gaseous fuels based on hydrogen production via electrolysis"; Tremel (2018), "Electricity-based fuels"; Agora Verkehrswende, Agora Energiewende and Frontier Economics (2018), *The Future Cost of Electricity-Based Synthetic Fuels.*

With increasing FLH the impact of CAPEX on the cost of production declines, leaving electricity costs and CO_2 prices for competing fossil fuels as the most relevant cost factors.

Overall conversion efficiencies for electricity to SNG are slightly higher compared to PtL, due to less complex product upgrading processes for SNG. Future production costs for large-scale SNG could be USD 40/MBtu of SNG by 2060 at an electricity cost of USD 50/MWh and USD 30/MBtu of SNG at an electricity cost of USD 30/MWh.[19] This is still significantly higher than the regional gas prices of USD 10–13/MBtu in the CTS by 2060. If SNG is produced from biogenic CO_2

[19] CAPEX assumptions: USD 455/kW_e for electrolyser and USD 564/kW for SNG; fixed operating and maintenance costs: 1.5% of CAPEX per year for electrolyser and 4% for FT synthesis; conversion efficiencies (LHV based): 74% for electrolyser (electricity to hydrogen) and 77% for FT synthesis (hydrogen to SNG); CO_2 capture costs: USD 30/tCO_2; FLH: 3 500 hours; electricity costs: USD 50/MWh; discount rate: 8%; technical lifetime: 30 years.

sources, a CO_2 price would improve its competitiveness by penalising natural gas, although the CO_2 price would have to be at USD 500/tCO_2 to make SNG at USD 40/MBtu competitive with a natural gas price of USD 12/MBtu, and still at USD 350/tCO_2 for SNG at USD 30/MBtu.

More than 40 PtG pilot and demonstration plants are in operation today, with 16 plants located in Germany alone. The largest plant in operation is the Audi e-gas plant in Werlte (Germany) with an electrolyser capacity of 6 MW_e to convert electricity from offshore wind into hydrogen, which is then used in a chemical synthesis together with CO_2 from a biomethane plant to produce SNG.

CO_2 reductions from CCU vs. CCS: Depending on the conditions, CCU and CCS could provide similar CO_2 reductions where the CCU is displacing the use of fossil fuels. For example, if the CO_2 is from biogenic origin – captured at a biomass power plant or liquid biofuel production plant – and the CO_2 is used to produce a synthetic fuel in combination with low-carbon hydrogen, the burning of this fuel does not create additional CO_2 emissions and the BECCU chain is carbon neutral (Figure 37).[20] Additional emissions reductions arise where the synthetic CCU fuel is displacing the use of fossil fuels.

In the BECCS pathway, the captured CO_2 is stored so that negative emissions are created by removing carbon from the atmosphere. These negative emissions can be used to offset CO_2 emissions associated with fossil fuel use elsewhere in the system, in more difficult to abate sectors, resulting in net zero emissions (Figure 37).[21]

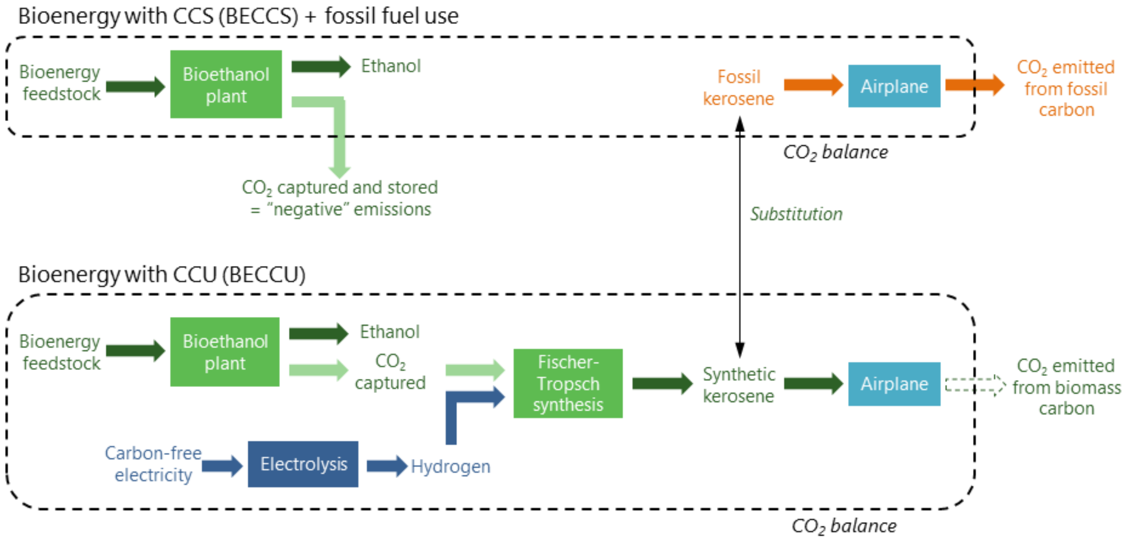
A critical difference in emission terms between BECCS and BECCU is that BECCS can create negative emissions. This becomes relevant when CO_2 emissions from the global energy system have to reach net negative emission levels, a situation observed in many deep decarbonisation scenarios in the second half of this century. BECCU, while being advantageous in some conditions, cannot produce negative emissions. The LCS analysis also highlights that BECCU is unlikely to reach the same scale of emissions reductions as BECCS, not least due to the in most cases higher abatement costs of BECCU.

If the CO_2 is from fossil energy sources, the CCU pathway leads eventually to CO_2 emissions when the produced synfuel is combusted. For CCU in fuel transformation, this means that eventually the CO_2 has to come from biomass or from DAC. Challenges exist in both cases. Availability of sustainable biomass for the energy sector is already a limiting factor in the CTS (see Box 3). Direct capturing CO_2 from the atmosphere is an alternative option and, though already demonstrated at pilot scale (e.g. Carbon Engineering), is a less mature technology. It requires further development to reduce the energy needed for capture (today based on Keith et al. [2018] at 8.81 GJ of gas per tCO_2, or 5.3 GJ of gas and 366 kW of electricity per tCO_2) or the collocation of DAC plants at sites with waste heat available from other industrial or energy conversion plants, such as FT biofuel plants (Graves et al., 2011).

20 The discussion focuses here on the comparison of CCS and CCU for CO_2 from biogenic sources. Similar conclusions can be drawn when comparing CCS and CCU for atmospheric CO_2 from direct air capture (DAC).

21 A similar comparison with similar conclusions can be made with hydrogen-enhanced biofuel production. Conceptually, the difference compared to the BECCU example shown in Figure 37 is that in a hydrogen-enhanced biofuel production process, the CO_2 (or CO) capture and synfuel production steps do not occur in separate plants, but in an integrated plant.

Figure 37. Comparison of CO_2 reductions from BECCS and BECCU



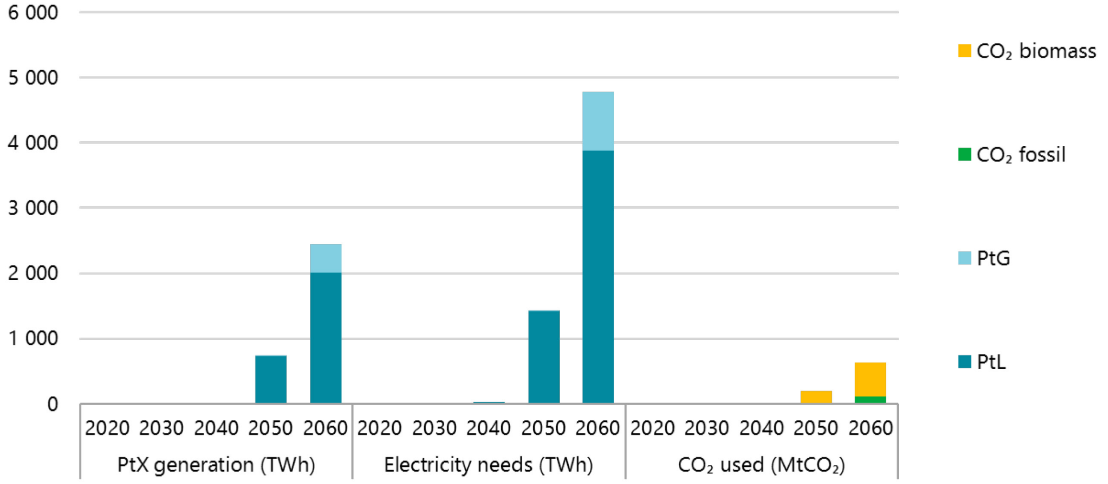
BECCU can have an impact on CO_2 emissions similar to BECCS, as long as the produced hydrocarbon fuel can substitute for fossil fuels. A unique feature of BECCS is that it can create negative emissions.

Energy impacts of CCU in the fuel transformation sector in the LCS

In the LCS, around 600 Mt CO_2 (corresponding to 6% of the remaining total global annual CO_2 emissions) would be used to produce 7 EJ of liquid fuels and 1.5 EJ of SNG in 2060 (Figure 38). Compared to the CTS, this would reduce global primary oil demand by 9% and gas demand by 2%. To achieve these fossil energy savings, however, significant efforts would be needed in the power sector. To produce the required hydrogen (13 EJ or 105 million tonnes of hydrogen [MtH_2] in 2060), 4 700 TWh of electricity would be needed in 2060, which represents around 9% of the global electricity generation in the LCS. The additional electricity needs would be largely covered by renewable electricity in the LCS.

Dedicated off-grid hydrogen production plants, located in areas with large and good renewable resources for electricity generation, could become a way to cover the electricity needs. As shown earlier in Figure 36, a key requirement is to provide low-cost electricity at relatively high FLH. Combining solar PV and onshore wind generation would be one option to achieve this (Box 7). A further consideration to take into account is the location of the CO_2 source relative to the electricity or hydrogen production site. Transport costs for electricity, hydrogen and CO_2 depend on distance and economies of scale, but in most cases it will be cheaper to transport the CO_2 by pipeline compared to hydrogen or electricity.

Figure 38. Fuel production, hydrogen and electricity demand of CCU options in the LCS



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

CCU options in the LCS would produce 2 400 TWh (8.5 EJ) of synthetic fuels in 2060, which would require 4 700 TWh or around 9% of global electricity generation.

Box 7. Can remote renewables become a resource for hydrogen production?

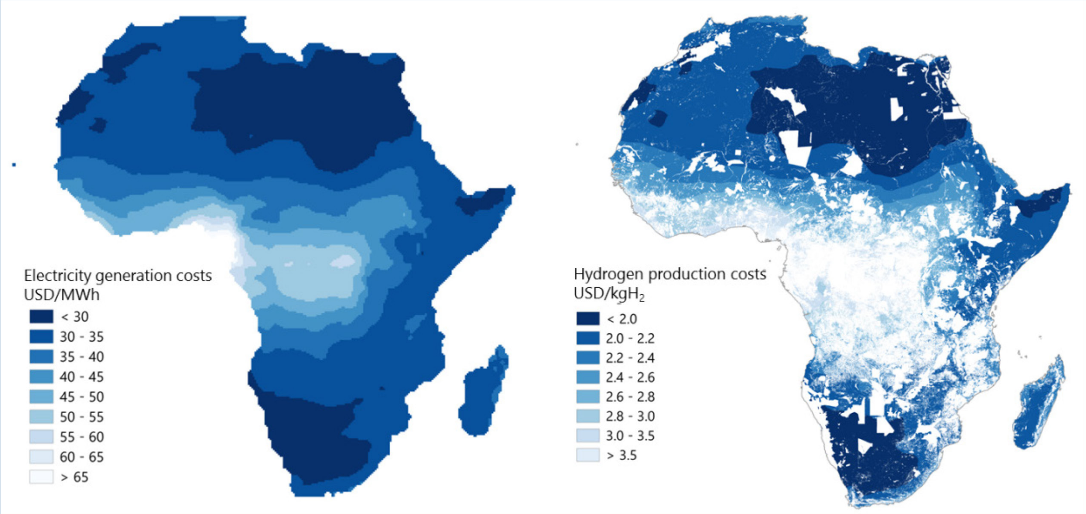
With rapid reductions in the cost of solar PV and onshore wind over recent years, hydrogen production from renewable electricity has gained renewed interest, with the aim of using hydrogen to decarbonise parts of the energy system for which direct electrification is difficult. Examples are aviation and shipping in the transport sector or high-temperature heat production in some industrial applications. Transporting and storing hydrogen is, however, difficult. Converting the hydrogen further into a fuel that can be more easily stored and transported could be a way to overcome this challenge. The synthesis of hydrocarbon fuels by combining hydrogen and CO_2 is one pathway being explored in various research and demonstration projects and creates fuels compatible with the existing energy infrastructure. Converting hydrogen with nitrogen into ammonia is another option, having the advantage of not requiring any carbon as input. Beyond its current uses as feedstock for fertiliser and other industries, ammonia can be used either as a fuel, e.g. in power generation or as shipping fuel, or it can be converted (after transport) back into hydrogen.

A prerequisite for all these pathways to be economically viable is the availability of low-cost and low-carbon hydrogen. An interesting option is the production of hydrogen through the electrolysis of renewables at locations in the world with large and cheap renewable resources. At the same time, to minimise the production costs of hydrogen, the electrolyser should run at high FLH. Excess renewable electricity generation, though having zero cost, is in most cases characterised by too low FLH to justify the operation of the electrolyser (resulting in high hydrogen costs). In addition, the related excess electricity volumes are likely to be small in comparison to the electricity requirements of PtL or PtG if they are to have a significant impact.

Dedicated renewable electricity generation for hydrogen production at places with large and good renewable resources could be an option to achieve both low-cost electricity and high FLH. Solar PV and onshore wind are particularly attractive due to their decreasing costs over recent years. Depending on local conditions, combining them in hybrid off-grid plants may be an opportunity to increase FLH and create more constant hydrogen production over time. The latter aspect is particularly relevant for subsequent PtL or PtG synthesis processes. Additional hydrogen storage tanks are an option to further steady the hydrogen input, but it also increases overall system costs.

The potential for and cost of hydrogen production from such dedicated solar PV and onshore wind generation (alone or combined as hybrid plants) have been analysed for various parts of the world to inform the analysis of PtL and PtG in the LCS. The figure below illustrates the electricity and hydrogen production costs from hybrid solar PV and wind systems in Africa. North Africa has vast solar PV potential at electricity costs below USD 30/MWh and 2 500 FLH in 2060, translating into hydrogen costs of USD 2 per kilogram of hydrogen (kgH_2). Also, when excluding protected areas, land dedicated to other, North Africa's remaining potential with a cost below USD 2/kgH_2 and within 200 kilometres of the coast is still large at 340 MtH_2, more than four times of global demand for pure hydrogen today. For the whole of Africa, the corresponding potential is 700 MtH2.

Hydrogen production from dedicated hybrid solar PV and onshore wind power plants in Africa



Notes: These maps are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area. Map on electricity costs does not include any exclusion areas, whereas the map on hydrogen costs considers exclusions due to other land uses and protected areas. Cost assumptions based on CTS in 2060: onshore wind = USD 1 540/kW_e; utility-scale solar PV = USD 625/kW_e; electrolyser = USD 455/kW_e; discount rate = 8%.

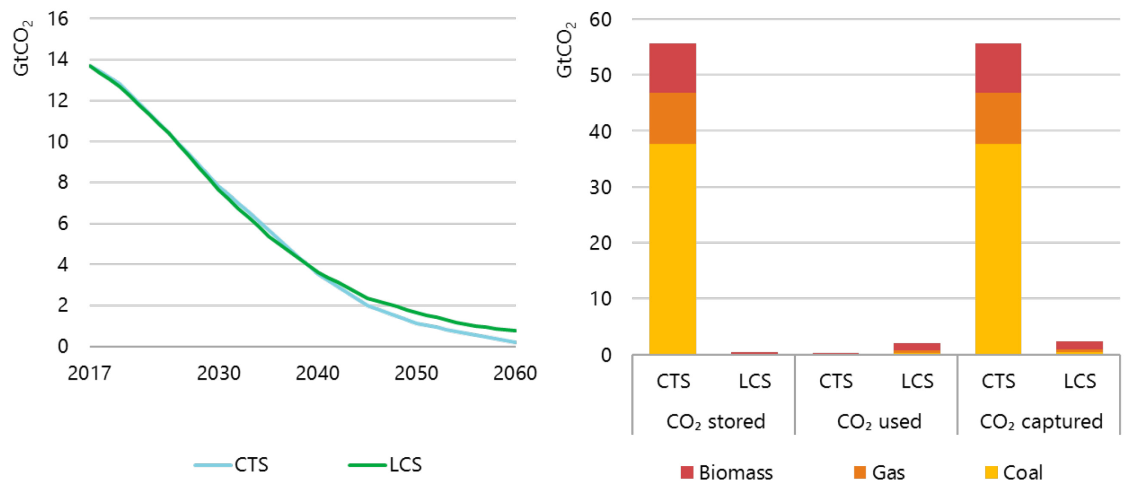
Sources: IEA analysis based on data from Rife et al. (2014), *NCAR Global Climate Four-Dimensional Data Assimilation (CFDDA) Hourly 40 km Reanalysis*; Pfenninger, S. and I. Staffell (2016), Long-term patterns of European PV output using 30 years of validated hourly reanalysis and satellite data; Staffell, I. and S. Pfenninger (2016), Using bias-corrected reanalysis to simulate current and future wind power output; UNEP-WCMC (2016), *World Database on Protected Areas User Manual 1.5*; USGS (1996), *Global 30 Arc-Second Elevation (GTOPO30)*; ESA and UCL (2011), *GLOBCOVER 2009: Products Description and Validation Report*.

In North Africa, electricity from solar PV could be an attractive option for hydrogen production, with electricity costs below USD 30/MWh resulting in hydrogen costs of USD 2/kgH_2.

In-depth analysis: Implications for power generation in the LCS

In the LCS, storage of CO_2 from power plants would be almost zero, a stark difference from the CTS where 56 Gt CO_2 from the power sector are stored from today to 2060 (Figure 39). Cumulative CO_2 emissions from the power sector would be only 2% higher compared to the CTS. Annual CO_2 emissions in 2060 would quadruple compared to the CTS, though from a very low level of 200 Mt CO_2 in the CTS. This increase in the power sector's emissions reflects that by excluding CO_2 storage, the costs for CO_2 abatement would increase, with marginal abatement costs reaching USD 450/tCO_2 by 2060. Consequently, mitigation options in other parts of the energy system would become more economic. Still, at a global average CO_2 intensity of 12 g CO2/kWh, electricity would be almost completely decarbonised by 2060.

Figure 39. Annual CO_2 emissions of global power sector and cumulative CO_2 stored, used and captured in the CTS and the LCS



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

More than 55 Gt CO_2 from the power sector are cumulatively stored by 2060 in the CTS, an amount corresponding to the sector's global CO_2 emissions over the last four years. In the LCS, almost no CO_2 from the power sector would be stored, while 2 Gt CO_2 would be captured and used for fuel and chemical feedstock production.

This would be largely achieved thanks to renewables, mainly solar PV and wind, which would account for 84% in the generation mix of the variant in 2060, compared to 77% in the CTS (Figure 40). Power generation with CO_2 capture would almost vanish by 2060, with a share of 1% in the generation mix. The captured CO_2 (around 2 Gt CO_2 cumulatively by 2060) would be almost completely utilised in the fuel transformation sector for the production of synthetic fuels or feedstocks.

Early retirement of coal-fired power plants, i.e. closing plants before they reach the end of their technical lifetime, would be required to drastically decarbonise the global power sector as in the CTS. Based on the technical lifetime of coal power plants existing today or under construction, around 750 GW of capacity could still be operating in 2060 and emit around 3.5 Gt CO_2 per year, an emission level clearly incompatible with the targets of the Paris Agreement. In the CTS, around 1 000 GW of coal-fired power capacity are retired early. In the LCS, the capacity retired prematurely would be, at 1 200 GW, somewhat higher, reflecting that retrofitting coal-fired power plants with CCU is no longer an economic option. Most of the early retirement of coal capacity in the LCS would occur in the period 2025–40, at a global average rate of 60 GW per year, while in the CTS the retirement rate over this period is 45 GW per year, a quarter lower.

As a result of early retirement of coal capacity in the LCS compared to the CTS, global electricity generation from coal power plants existing today or under construction would be, on a cumulative basis, 20 200 TWh lower in the LCS over the time period 2017–60. This reduced coal-fired electricity generation from plants either existing or under construction, but for which the original investment must be paid in any case, would result in lost revenues that are estimated (on an undiscounted basis) at around USD 1.8 trillion between 2017 and 2060. This would mostly affect Asian countries with a quite young coal fleet today, with an average age of 9 years in China and 12 years in India, while the average age of the coal fleet in Europe is 30 years and 36 years in the United States. Accordingly, almost two-thirds of these estimated lost revenues would occur in China and a quarter of them in India.

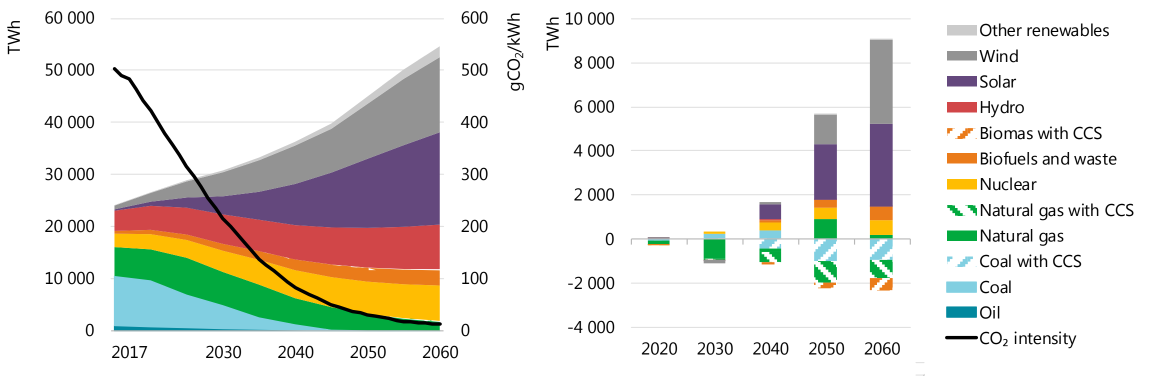
The captured CO_2 from retrofitted coal-fired power plants could be used for the production of synthetic hydrocarbon fuels (PtL, PtG), substituting fossil fuels and resulting in similar CO_2 reductions to the counterfactual case of storing the CO_2 and continuing the use of fossil fuels. In the LCS, however, it would be more cost-effective to retire the coal-fired power plants early instead and replace them with renewable power generation (or to a much smaller extent with nuclear).

Limiting CO_2 storage would lead overall to much higher electricity generation, being 13% higher in 2060 compared to the CTS. This would be to some extent driven by increased electrification of transport and industry as a CO_2 mitigation option, while a slightly higher cost for residential and commercial electricity would trigger efficiency measures that would lead to reduced electricity demand. As a net effect, global final electricity demand would increase by 900 TWh in 2060 in the LCS, or 2% compared to the CTS. Combined with energy efficiency improvements, electricity's share of global final energy demand in 2060 would increase from to 36% in the CTS to 39% in the LCS.

The largest impact on electricity demand, however, would come from the fuel transformation sector, where around 4 700 TWh (or 9% of global electricity generation) in 2060 would be used for the production of synthetic hydrocarbon fuels through PtL and PtG. This additional electricity demand would be largely covered by dedicated off-grid renewable electricity generation, largely from solar PV and wind, with parts of it in combined hybrid solar PV and onshore wind systems to increase FLH for hydrogen electrolysis. Therefore, this dedicated power generation, though largely based on variable renewable energy, would not pose the integration challenges caused by grid-connected VRE.[22]

[22] Having said that, energy storage can play a role for the production of hydrogen-based fuels from dedicated solar PV and/or wind generation. Energy storage in the form of battery storage can be used to increase the FLH of the electrolyser, while hydrogen storage can be an option to increase the utilisation of the fuel synthesis process. Whether investments in such additional storage make economic sense (compared to the alternative of curtailing some of the electricity) has to be assessed in the context of the overall plant design and its local conditions, such as hourly solar PV and/or wind generation profiles.

Figure 40. Global electricity generation in the LCS (left) and changes relative to the CTS (right)



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

In the LCS, CCS in the power sector would be largely replaced by solar PV and wind, which also would cover the additional electricity demand. This would be mainly used for the production of hydrogen-based fuels and feedstocks, and would result in a 13% increase in electricity generation in 2060 compared to the CTS.

As conventional fossil power plants, CCS power plants can contribute to balancing variations in electricity generation and demand. This is particularly true for seasonal variations, which are difficult to meet through battery storage due to the limited capability to store energy over longer time periods. On the demand side, seasonal variations in electricity demand can be driven by heating or cooling needs, while on the generation side weather seasons can influence renewable electricity generation. Examples are the seasonality of India's wind generation, with peaks during the monsoon season, or the decline in PV generation during winter months in Europe. With increasing shares of these renewable sources in the generation mix to decarbonise the power sector, these seasonal imbalances can become more pronounced in some parts of the world. Furthermore, weather conditions that lead to very little wind and solar generation may coincide with periods of high demand for a period of several days, e.g. several days of foggy weather with no sunshine or wind during winter months in Europe.

In the CTS, power plants equipped with CCS in 2060 have an installed capacity of 615 GW globally, providing around 3 400 TWh of dispatchable electricity generation. They thus provide short-term flexibility on a daily level to some extent, but also balance seasonal variations in renewable generation and electricity demand. In the LCS, the loss of this dispatchable generation would be compensated by increased generation from dispatchable power plants (up 2 270 TWh in 2060 relative to the CTS), namely from natural gas without CCS, bioenergy without CCS, nuclear power and solar thermal energy. The remaining gap would be covered by a combination of solar PV and wind power, with flexibility needs for storage and demand response increasing to 1 560 GW in the LCS compared to 1 430 GW in the CTS.

Converting electricity into a storable fuel (hydrogen, SNG from PtG, ammonia), which can then be used for power generation, is a further option to address seasonal imbalances. In the LCS, PtG would allow the continued use of the existing gas infrastructure for transport and seasonal storage, as well as the subsequent use of the SNG in power plants. This is, however, a relatively costly option, so that on average only 2% of the remaining natural gas use in the power sector in the LCS in 2060 would be based on PtG.

Large-scale electricity interconnections between regions with different seasonal patterns of electricity demand or of renewable electricity production could be a further way to balance seasonal variations, e.g. higher winter electricity demand in Northern Europe could be covered by otherwise unused solar resources in North Africa. Such large-scale and long-distance interconnections are technically feasible. At the end of last year the world's longest transmission line (based on ultra-high-voltage direct current technology with a transmission capacity of 12 GW) commenced operation in China, connecting northwest China's Xinjiang Uygur Autonomous Region and China's Anhui province in the east over a distance of 3 324 kilometres, roughly equivalent to the distance between Moscow and Madrid. While technically feasible, long-distance interconnectors may face political challenges and security concerns, especially when involving not only the importing or exporting countries, but also several transit countries. For these reasons, long-distance interconnectors have not been investigated as a seasonal balancing option in the scenario analysis.

Overall, while CCS in the CTS plays an important role in providing system flexibility, in particular on the seasonal scale, its almost complete elimination from the power sector in the LCS would require investment in alternative dispatchable low-carbon generation options. This, in total, would lead to an additional capacity need for dispatchable power technologies (gas turbines and combined-cycle gas turbines without CCS, biomass power, nuclear power, solar thermal power, electricity storage) of around 900 GW in 2060, resulting in additional investment of USD 1.3 trillion over 2017–60.

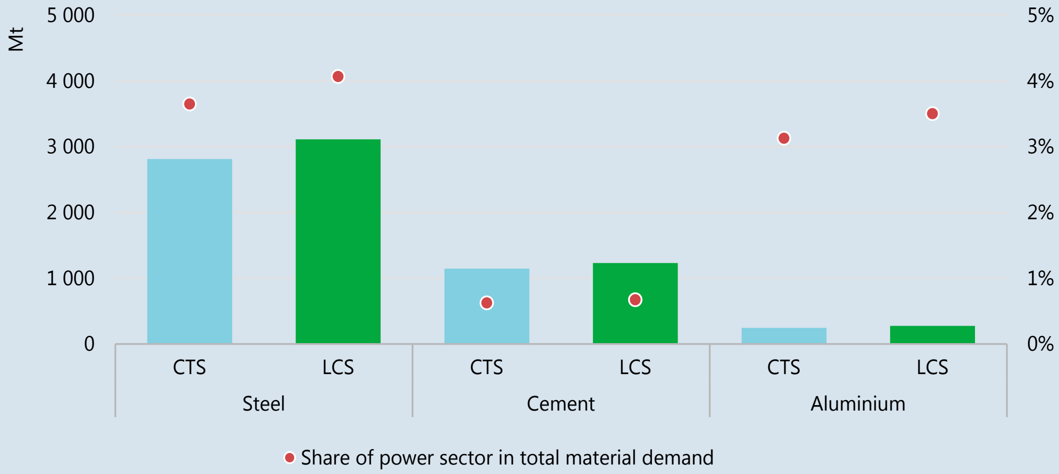
Box 8. What are the impacts on demand for materials in the power sector if CO_2 storage were limited?

While the LCS would lead to lower consumption of fossil fuels by having fewer coal- or gas-fired power plants with CCS and by the substitution of fossil oil and natural gas with synthetic fuels from hydrogen, the impact on material needs to build power generation capacity is not immediately clear. Electricity generation in the LCS would be 13% higher compared to the CTS, which would drive up capacity needs, in particular solar PV and wind, and the related material needs to build these technologies. At the same time, the capacity mix would be different, with fossil-based power plants with CCS almost completely disappearing in the LCS.

The implications of the power sector on steel, cement and aluminium demand have been assessed based on new additions to power technology capacity in the scenarios and their material intensities. The overall impacts of the LCS on material needs would be moderate. Cumulative material demands during 2015–60 would increase by 11% for steel, 8% for cement and 12% for aluminium, relative to the CTS. The impacts on global material demand would be smaller, with the power sector being responsible for a 0.4% increase in cumulative steel demand in the LCS, a 0.4% increase in aluminium demand and a 0.05% increase in cement demand. These increases in total material demand may appear small, but may still be challenging for the industrial sector, given limited availability of CCS and the need to rely on more costly production pathways in the LCS.

The cumulative needs of the power sector for steel, cement and aluminium would increase in the LCS by 8–12% relative to the CTS.

Cumulative global material needs for power generation in the CTS and LCS



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

In depth analysis: Implications for the buildings sector in the LCS

If CO_2 storage deployment were limited, additional building measures beyond the CTS would be needed to support the transition to a low-carbon energy sector. They would consist of:

- A more assertive and rapid phase-down of coal- and oil-fired technologies in buildings.
- A shift of gas assets (including gas-condensing boilers) to cleaner and more efficient heating technologies such as electric heat pumps, solar and district energy.
- Accelerated deployment of high-efficiency technologies across all building end uses.
- Greater uptake of renewables, such as solar thermal and modern use of solid biomass.

Direct emissions from fossil combustion in buildings would still amount to 87 Gt in the CTS over the period 2018–60, or all the CO_2 emitted over the past 43 years by Germany, France, Italy and the United Kingdom combined. The LCS would require phasing out coal and oil more rapidly to reduce these direct emissions. In 2030, the market share of coal- and oil-fired heating equipment in the buildings sector would drop to 5% in 2030 globally, and would be totally phased out by 2050.

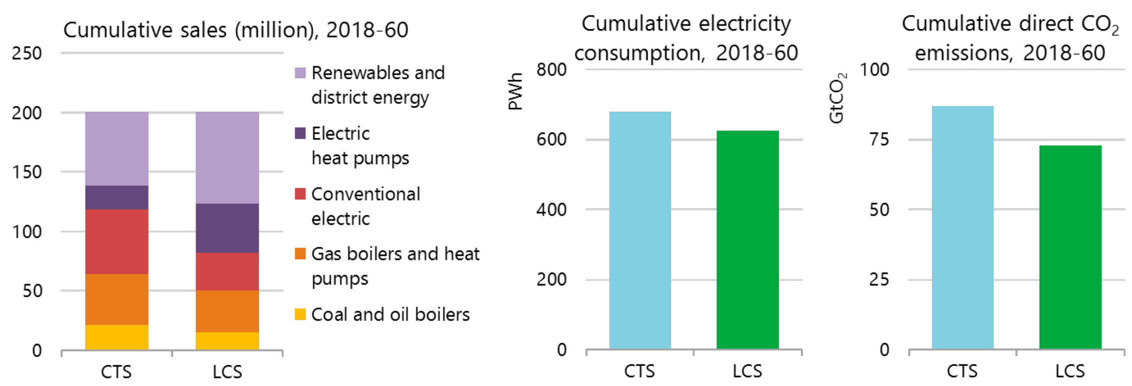
Additional reductions in direct buildings emissions would result from strategic investments to phase down inefficient gas-fired technologies. While the CTS assumes that markets move away from conventional non-condensing gas boilers for heating, the LCS would go further in phasing down condensing gas boilers as well. A strategic shift from gas to more efficient electricity-driven technologies and district energy would help achieve climate mitigation objectives while bringing greater flexibility to the electricity system. Taken together, all measures pursued would lead to a nearly 15% reduction in cumulative direct fossil fuel-related emissions from buildings relative to the CTS.

Indirect emissions from electricity and commercial heat generation would amount to roughly 100 Gt cumulatively to 2060 in the CTS. This scenario assumes that best available technologies would be gradually deployed to achieve high energy efficiency performance levels in the long term. The LCS would tap into the potential for upfront electricity saving by deploying these high-efficiency technologies more rapidly in the coming decade across all building end uses. For instance, markets would move to light-emitting diodes with an efficiency above 150 lumens per watt in the next 10 years, while heat pumps with coefficients of performance exceeding 4 and air conditioners with seasonal energy efficiency ratios greater than 6 would be deployed before 2030. In the CTS, those market average efficiency levels are achieved more incrementally by 2040.

Additional measures to increase the use of renewable sources of energy would reduce electricity and fossil fuel consumption further in the LCS. Solar technologies for heating and cooling include PV systems with heat pumps or thermally driven heat pumps using heat as a power source. Storage capacity, modern district energy networks and digitalisation would also bring flexibility to energy networks to accommodate such intermittent energy sources. The efficient use of solid biomass, for example for heat generation, would equally supports the shift away from fossil fuels.

The strategic decline of coal, oil and gas use in buildings would reduce buildings sector direct emissions by 14 Gt CO_2 in the 2018–60 period in the LCS (Figure 42). This represents nearly 80% of the total buildings sector carbon abatement potential (includes direct and indirect emissions) from the CTS to the LCS. Other energy efficiency measures would generate more than 1 200 TWh of electricity savings annually, alleviating the pressure on the power sector and facilitating its decarbonisation.

Figure 41. Cumulative buildings sector heating technology sales, direct CO_2 emissions and electricity consumption in the CTS and LCS, 2018–60



Notes: PWh = petawatt hour. Analysis above uses the Energy Technology Perspectives modelling framework.

Avoiding 14 million sales of fossil fuel equipment in buildings would reduce direct emissions by 15% in the LCS, while greater uptake of energy efficiency and renewables would support the decarbonisation of the power sector.

In-depth analysis: Implications for the transport sector in the LCS

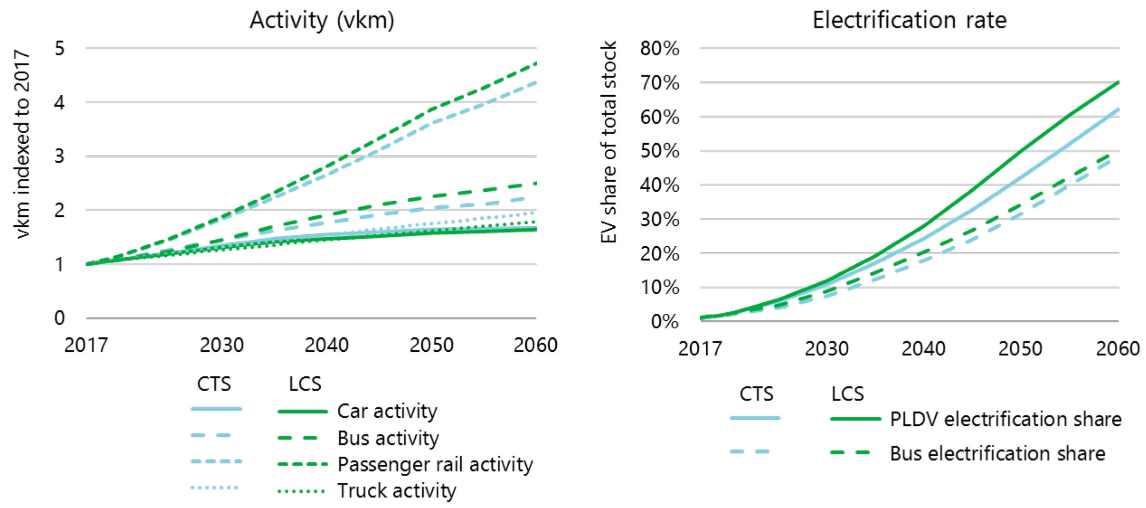
Limited CCS deployment would also have implications for transport. Additional policy pushes would need to target measures with high potential for carbon abatement, namely electrification of road transport modes, improved logistics in road freight, and "avoid-shift" measures.[23] Fuel and vehicle taxes would need to be higher than in the CTS. City-level policies would be needed to internalise the externalities of car use and to promote the build-out and modernisation of public transport networks to spur efficiencies in road transport modes and a shift to buses and rail. These would need to be coupled with policies to promote the market uptake and continuing technological development of electric vehicles. As shown in Figure 42, the above policy measures would need to realise the following carbon abatement measures over and above the CTS:

- more rapid penetration of electric powertrains in PLDV and bus fleets
- an additional 2% reduction in activity (in vkm) of PLDVs by 2060
- a concomitant increase in bus and rail activity (vkm), which would increase by 16% and 8%, respectively, by 2060
- a reduction in road freight activity (vkm), which would result from a push for greater operational efficiencies coming from improved routing, improved vehicle utilisation (i.e. greater average loads), and reduced empty running, such that total truck vkm would be 9% lower by 2060.

Cumulative direct CO_2 emissions from transport over the period 2017 to 2060 would be reduced by 15 Gt, from 267 Gt in the CTS to 252 Gt in the LCS. The majority of the reductions would come about through reduced gasoline and diesel demand over the period 2018–60 (by 6% and 10%, respectively). Cumulative electricity demand from plug-in and battery electric vehicles would be higher in the LCS variant (by 14%), despite the fact that increases in the share of electric PLDVs and buses would be somewhat offset by a smaller total PLDV stock (Figure 43).

[23] "Avoid-shift" measures reduce the number and length of discretionary trips in high carbon-intensity modes (e.g. cars and passenger aviation) and increase the modal share of public transport. They include fiscal incentives (e.g. congestion charging), regulations (e.g. low-emission zones), investment in public transport, and integrated urban land use and transport planning.

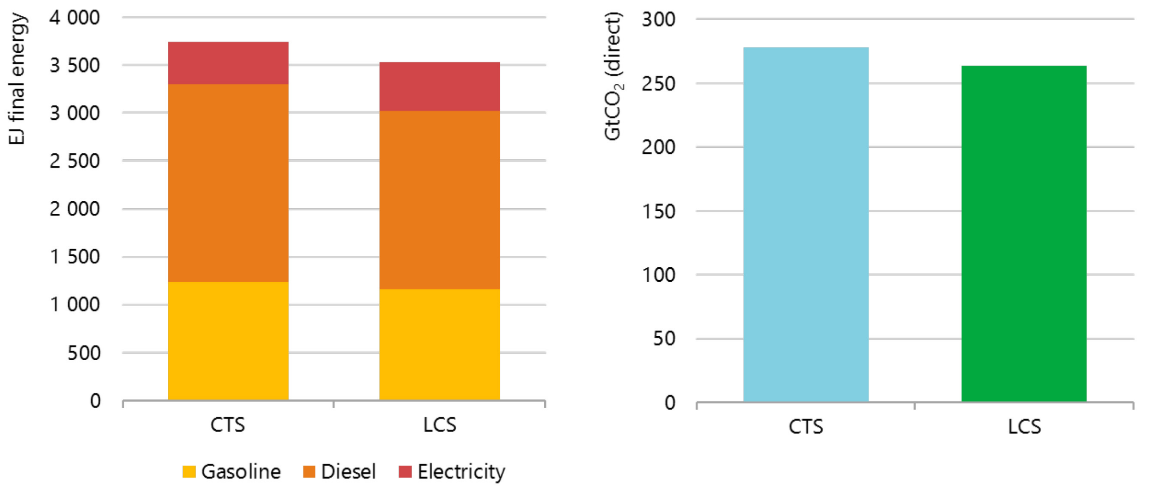
Figure 42. Key additional mitigation actions in LCS compared to CTS, 2017–60



Notes: EV = electric vehicle. Analysis above uses the Energy Technology Perspectives modelling framework.

Fuel taxes pegged to the well-to-wheel greenhouse gas emissions intensity of fuels, together with vehicle taxation and city-level measures to promote a diversity of transport options, would lead to additional emissions reductions of 15 Gt CO_2 in the LCS.

Figure 43. Fuel consumption in the LCS compared to the CTS, cumulative to 2060



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

Pricing policies would make the use of oil-based fuels more expensive in the LCS. These would be complemented by measures that promote vehicle electrification. The results would be smaller fleets, lower gasoline and diesel demand, and an increase in electricity demand.

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4. Enabling policy and stakeholder actions

The CTS is a highly ambitious scenario that relies on a portfolio of technologies and measures to achieve long-term climate goals. In the CTS, energy sector CO_2 emissions are reduced by 75% by 2060 from current levels, resulting in cumulative abatement of 750 Gt CO_2 relative to the RTS. The scale of the challenge inherent in this is underscored by the sustained growth in energy-sector CO_2 emissions, which increased by 1.7% in 2018 to reach a record high of 33.1 Gt (IEA, 2019).

The LCS analysis has highlighted that if the contribution of a key mitigation option were limited, in this case CO_2 storage, this could substantially increase the cost and complexity of the energy transition. It demonstrates the importance of pursuing all technology options to maximise the opportunity for a rapid and sustained decline in global energy CO_2 emissions. The LCS analysis also highlights the value of continued support for technological innovation and the need for an integrated and systems-wide approach to policy development.

Accelerating CCUS deployment: A focus on CO_2 storage

Recognising the contribution of CO_2 storage to reducing emissions across the power, industrial and fuel transformation sectors, the CTS and LCS analysis underscores the importance of action to support the accelerated deployment of CCUS technologies and infrastructure. This includes targeted policies to incentivise investment, the early identification and development of lower-cost deployment opportunities, and strengthened global partnerships (IEA, 2017). The LCS analysis also highlights the need for a continued focus on geological storage development in parallel with CO_2 use opportunities, since CO_2 use could play an increased role but cannot offer an alternative to storage.

Priority actions to support CO_2 storage development include:

- Invest in the exploration and assessment of CO_2 storage: Confidence in the availability of safe, secure and adequate CO_2 storage is a prerequisite for investment in infrastructure for the transport of CO_2 and CO_2 capture facilities. While global CO_2 storage resources are considered to be well in excess of future requirements, significant further assessment is required to convert theoretical CO_2 storage into "bankable" storage, where capacity, injectivity and containment are well understood.
- Establish legal and regulatory frameworks for CO_2 storage: Stable and transparent legal and regulatory frameworks that address key issues – including long-term monitoring requirements and liability for the stored CO_2 – are crucial to enable commercial investment in CO_2 storage. The ratification of the London Protocol to the Convention on the Prevention of Marine Pollution is needed to allow for the transport of CO_2 across borders for offshore geological storage.
- Facilitate planning and investment for CO_2 infrastructure: The widespread deployment of CCUS at the scale and pace of the CTS is predicated upon substantial investment in CO_2 transport and storage networks that can service multiple facilities across the energy

system. The development of CCUS "hubs" can reduce unit costs through economies of scale while reducing commercial risk by separating the key elements of the value chain: capture, transport and storage. Public–private partnerships could play an important role in the planning and development of these networks, including to support appropriate risk-sharing arrangements.

Supporting technological innovation

The LCS highlights that if CO_2 storage failed to be deployed at scale, there would be an increased reliance on alternative technologies that are at an earlier stage of technology readiness or commercialisation, including synthetic hydrocarbon fuels, electrolytic hydrogen and hydrogen-based DRI for steel production. Enlarging the portfolio of innovation streams for these technologies could maximise the technology options available to support deep emissions reductions in the future and reduce the associated costs and technology risks.

Beyond 2060, continued limits on the availability of geological CO_2 storage could substantially curtail the availability of many CDR or negative emissions technology options. Recognising the importance of carbon removal in the 1.5 degree pathways considered by the IPCC, further innovation on alternative CDR technologies may be required if CO_2 storage were not developed at scale.

Public and private support for energy innovation should be available through all stages of the technology cycle, including early-stage research for radically innovative technologies through to near-commercial technologies. Technology-pull measures can also incentivise deployment of best available technologies and encourage the phase-out of less efficient processes in the near term.

Improved integration of policy measures

The CTS and LCS analysis demonstrates the interlinkages between sectors and the potential impacts across the energy system if there were a failure to develop CO_2 storage. In addition to requiring greater mitigation efforts and behavioural changes in the buildings and transport sectors, the LCS would result in an increased demand for low-carbon power, including dedicated off-grid renewable electricity generation, and a significant scale-up of hydrogen infrastructure.

Strong and consistent policies are required across energy systems to recognise and respond to these interlinkages to support efficient and timely investments. These policies need to cover CO_2 transport and storage infrastructure, which will be needed to service facilities across multiple sectors; power system planning, which will be impacted by developments in end-use sectors; and measures to support the optimal use of limited biomass resources. A carbon price can be an effective mechanism for economy-wide emissions reductions and to promote investment decisions consistent with long-term climate goals. However, even with carbon pricing, complementary and dedicated support for the development and deployment of technology will be needed to follow a CTS pathway.

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General annexes

Annex I. Reference and Clean Technology Scenarios

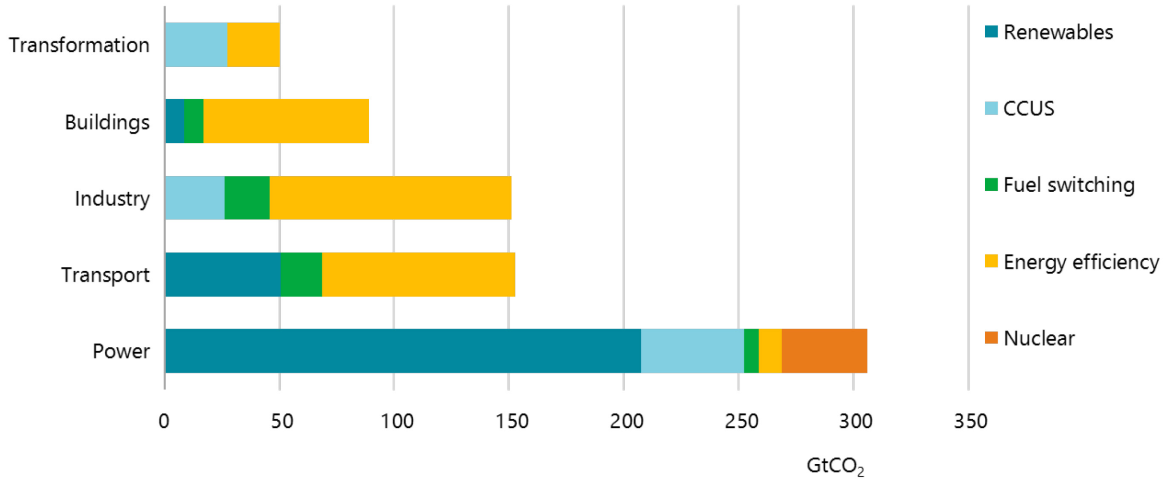
Global total energy-related carbon dioxide (CO_2) emissions reached a historic high of 34.9 gigatonnes of carbon dioxide (Gt CO_2) in 2017.[24] Power and energy transformation accounted for 43%, industry for 24%, transport for 23% and buildings for 9%. If emissions from electricity generation are attributed to end-use sectors, the shares of energy-related emissions in buildings and industry rise significantly – to approximately 25% for buildings and nearly 40% for industry. In 2017, global total primary energy demand reached 585 exajoules (EJ), having risen at an average annual rate of 2.0% since 2000.[25] Fossil fuels represent most of the total primary energy demand, with a share of approximately 80% in 2017 (nearly unchanged since 2000). The final energy demand drives the total primary energy demand. In 2017, final energy demand reached 420 EJ, with the industry[26] sector accounting for the largest share (37%), followed by buildings (30%), transport (28%) and agriculture and other (5%).[27]

Announced policies and commitments considered in the Reference Technology Scenario (RTS) are not enough to significantly bend the emissions curve. In the RTS, emissions continue to grow until 2045, when they level off at just over 39 Gt CO_2 before gradually beginning to decline post 2050 to 38 gigatonnes (Gt) by 2060. This is up 8% from the 2017 level, and more than four times above the path towards energy sector decarbonisation as outlined in the Clean Technology Scenario (CTS). Primary energy demand grows by 38%, to over 800 EJ by 2060. Fossil fuels remain the largest source of energy supply, but their share declines to two-thirds in 2060 as the share of renewable sources of energy (renewables) and nuclear energy reaches one-third. Final energy demand grows to approximately 580 EJ, an increase of about 40% above the 2017 level. Electricity shows the largest increase in absolute terms, more than doubling between 2017 and 2060, and reaching a share of 28%. However, it is still below that of oil, which falls slightly to 33%.

The CTS represents a markedly different path from the RTS. Energy sector emissions in the CTS decline to 8.7 Gt CO_2 by 2060, which is 75% below the 2017 level. All sectors will need to reduce CO_2 emissions, with power reaching near decarbonised levels to facilitate further decarbonisation of the end-use sectors. Cumulative emissions abatement to 2060 is highest in the power sector at 300 Gt CO_2, followed by transport and industry with each abating 150 Gt CO_2 (Figure 44). Cumulative abatement in buildings is just under 100 Gt CO_2, while the transformation sector reduces about 50 Gt CO_2. Energy efficiency across end-use sectors accounts for the largest share of total emissions reduction, representing 39% of cumulative reductions, followed by renewables (36%), carbon capture, utilisation and storage (CCUS) (13%), and switching to lower-carbon fossil fuels (7%) and nuclear power generation (5%).

[24] Energy-related emissions include fuel combustion emissions and industrial process emissions.
[25] Growth is calculated as compound annual growth rate.
[26] Includes energy use for coke ovens, blast furnaces and chemical feedstocks.
[27] Includes non-energy use for refineries and other non-specified.

Figure 44. Cumulative global CO_2 emissions reduction by 2060 split by technology area: RTS to CTS



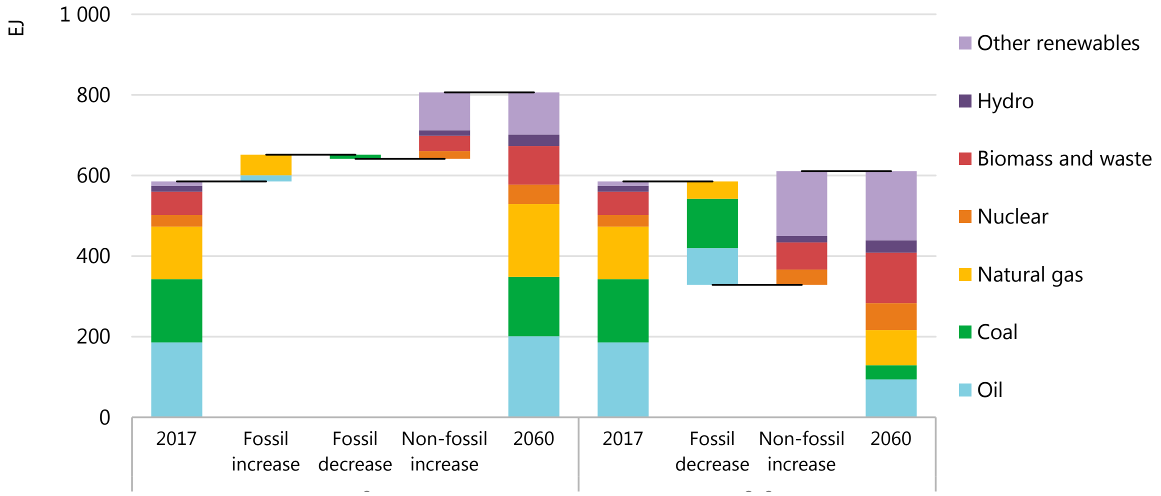
Note: Analysis above uses the Energy Technology Perspectives modelling framework.

Energy efficiency, renewables and CCUS are central to reducing energy-related emissions.

Under the CTS, a dramatic shift in the global energy mix is needed. The share of non-fossil fuel sources surpasses that of fossil fuels to reach nearly two-thirds of the total primary energy demand in 2060 compared to just one-third under the RTS (Figure 45). Renewable energy from solar, wind, geothermal and ocean energy becomes the largest fuel source category (28%), followed by biomass and waste (20%).[28] Oil remains the largest fossil fuel (15% of total fuels), as it continues to be the largest fuel source for aviation, shipping, trucking and chemical feedstock; however, its use is more than halved compared to in the RTS. Total final energy demand falls by 4% by 2060 relative to 2017, compared to the substantial increase seen in the RTS, as stringent energy efficiency measures are assumed to be adopted. Electricity becomes the largest end-use fuel, reaching a share of 36%, with absolute electricity consumption nearly doubling between 2017 and 2060.

[28] Biomass and waste includes solid biomass, gas and liquids derived from biomass, industrial waste and the renewable part of municipal waste. It includes traditional and modern biomass.

Figure 45. Global primary energy demand by scenario



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

Non-fossil fuel energy will meet more than two-thirds of primary energy by 2060 in the CTS.

The decarbonisation of the **power sector** is central to any strategy to transform the energy system. In the RTS, gross electricity generation more than doubles, reaching nearly 53 000 terawatt hours (TWh), by 2060 (Figure 46). The share of fossil fuel generation falls from 65% in 2017 to 40% by 2060, as the share of renewables (mainly wind, solar photovoltaics [PVs] and hydro) reaches over 50%. Emissions intensity of power generation continues its steady decline. By 2060, it falls to 250 grammes of carbon dioxide per kilowatt hour (g CO_2/kWh), less than half the 2017 level. While this shift towards decarbonised electricity is encouraging, it is not sufficient to achieve a deep reduction in power sector emissions.

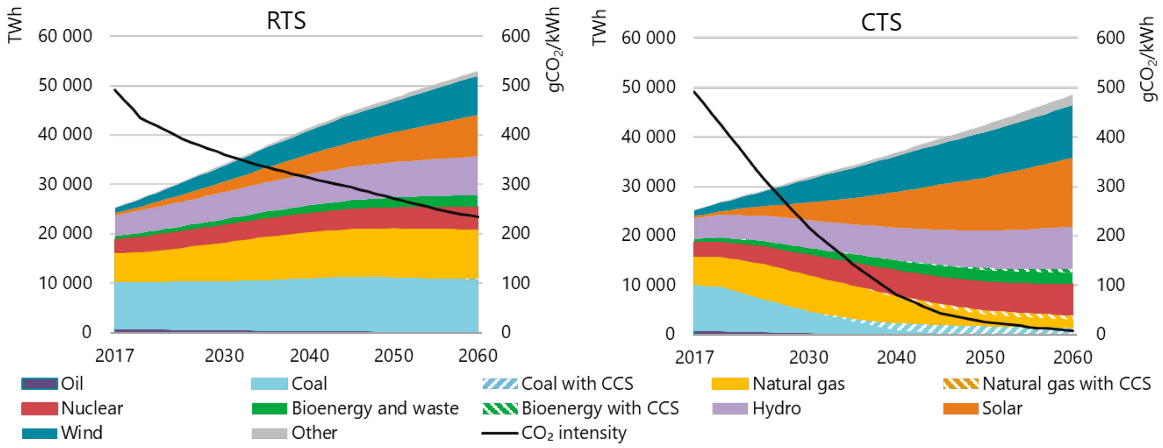
In the CTS, the CO_2 intensity of electricity reaches the very low level of 4 g CO_2/kWh by 2060. This will require a rapid roll-out of renewable electricity generation technologies (accounting for approximately 80% of total electricity generation by 2060), and a range of flexibility measures to support high levels of variable renewable generation.[29] The share of fossil fuel generation declines to just 8%, of which more than 60% will be with carbon capture and storage (CCS). Nuclear generation in the CTS sees a renewal, with generation more than doubling and its share rising to 13% by 2060. The CTS leads to a revolution of the **fuel transformation sector**,[30] with a rapid decline in energy for fossil fuel extraction and oil refining, and strong growth in demand for liquid and gaseous biofuels. Biofuel production plants equipped with CCS allow the fuel transformation sector to reach net negative CO_2 emissions levels of -1 Gt CO_2 in 2060.[31]

In the **industrial sector**, limited progress is expected in the development and deployment of low-carbon measures in the RTS. Demand for energy-intensive materials such as steel, cement and chemicals remains high as emerging economies continue to develop their infrastructure

[29] Variable renewable energy sources are onshore and offshore wind, solar PVs, run-of-river hydropower and wave energy. The focus here is specific to the integration of wind and PVs, so the discussion of variable renewable energy is limited to these two.
[30] The fuel transformation sector covers energy use for coal mining, oil and gas production, and further conversion of primary energy into final energy carriers (except electricity and heat).
[31] Biofuel consumption remains within an International Energy Agency estimated budget of sustainable biomass availability.

and their population grows. Many of these materials are highly traded commodities that compete in global markets, which poses concerns in some countries about the effectiveness of implementing domestic CO_2 emissions reduction mechanisms. Total energy demand in industry grows sharply (up approximately 40% by 2060 compared to in 2017), and remains dependent on fossil fuels (63% in 2060 versus 70% in 2017). Direct energy and process emissions from industry grow by approximately 15%, reaching 9.7 Gt CO_2 by 2060, which is slightly below a peak in emissions around 2045 at 9.9 Gt CO_2.

Figure 46. Global electricity generation by scenario



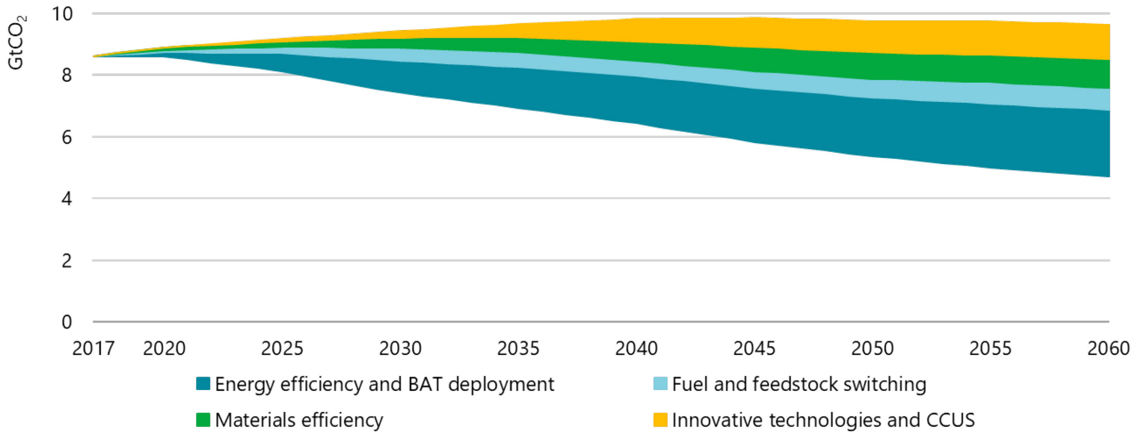
Notes: Other is geothermal and ocean energy. Hydro does not include generation from pumped storage. Analysis above uses the Energy Technology Perspectives modelling framework.

Electricity generation will reach near decarbonised levels by 2060

To achieve a low-carbon and cost-effective transition in industry as outlined in the CTS, industry-related emissions peak by 2020. They then fall by about 45% below the 2017 level by 2060, to just under 5 Gt CO_2, which is half the level reached in 2060 in the RTS (Figure 47). Energy efficiency strategies and deployment of best available technology (BAT), particularly in emerging economies, help to curb total energy demand, which declines by almost 30% under the CTS in 2060 relative to the RTS. The share of fossil fuels in industry falls to about 55% by 2060, from approximately 70% today. This is due to a combination of increased electrification and a move away from coal towards biomass. Energy efficiency and fuel switching account for 46% and 15% of cumulative emissions reduction to 2060 in the CTS relative to the RTS.

Material efficiency strategies account for 19% of cumulative emissions reduction to 2060 in the CTS relative to the RTS. These strategies include improving manufacturing yields, reusing material by-products across industrial processes, designing products and buildings that require less materials, and increasing recycling and reuse after disposal. Development, demonstration and deployment of innovative low-carbon industrial processes will also play an important role in addressing industrial emissions, accounting for 20% of cumulative emissions reduction. Innovative low-carbon industrial processes include production routes that rely on renewable electricity (either directly or through electrolytic hydrogen), use of alternative raw materials and use of CCUS to reduce process and energy emissions.

Figure 47. Industry sector direct CO_2 emissions reduction in the CTS relative to the RTS



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

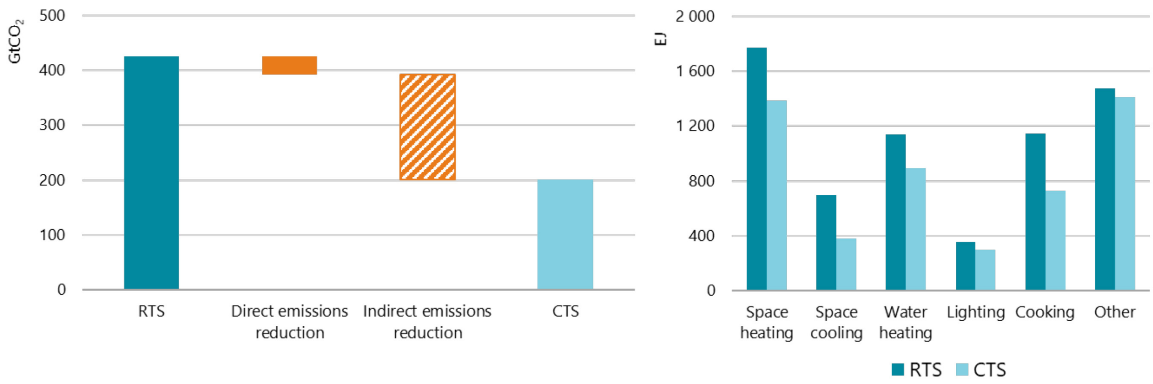
Energy efficiency accounts for almost half of the cumulative industrial emissions reduction in the CTS relative to the RTS, with other strategies contributing similarly to the remaining reduction effort.

In the **buildings sector**, final energy demand rises by nearly 40% between 2017 and 2060 in the RTS. This is because economic development drives rapid growth in floor area alongside increases in consumer demand for energy services. In particular, cooling energy demand more than triples by 2060 as expectations for cooling comfort grow, especially in hot and humid climates. Electricity is the largest fuel source, and sees its share rise from one-third in 2017 to one-half in 2060. Fossil fuel use continues to decline, but still represents about 25% of the final energy demand in 2060 (compared to approximately 35% in 2017).

Energy efficiency in all buildings end uses is central to achieving CTS ambitions in the buildings sector. Final energy demand by 2060 in the CTS is one-third lower than in the RTS. Energy efficiency equally allows for greater electrification of end uses while still consuming 20% less electricity than in the RTS. For example, the CTS uses approximately half as much final energy cumulatively as the RTS to meet the same cooling service, due to more-efficient air conditioners and improved buildings design (Figure 48). Efficient lighting also reduces electricity demand growth, although a considerable portion of that potential is being accounted for in the RTS, as the sales share of light-emitting diodes already exceeded 30% in 2017. Shifts to high-efficiency equipment and renewable sources for space and water heating also help to decarbonise heat, which accounted for more than 50% of the total final energy demand in buildings in 2017.

Cumulative buildings-related emissions (direct and indirect) to 2060 in the CTS are just over 50% lower than in the RTS. This is due to a combination of lower fossil fuel use, efficiency measures that reduce overall energy use, and lower indirect emissions owing to the decarbonisation of electricity supply.

Figure 48. Buildings sector cumulative CO_2 emissions and energy use by activity, 2017-60



Notes: *Indirect emissions reduction* includes the impact of energy efficiency, which lowers electricity use, as well as the decarbonisation of electricity and heat production. Analysis above uses the Energy Technology Perspectives modelling framework.

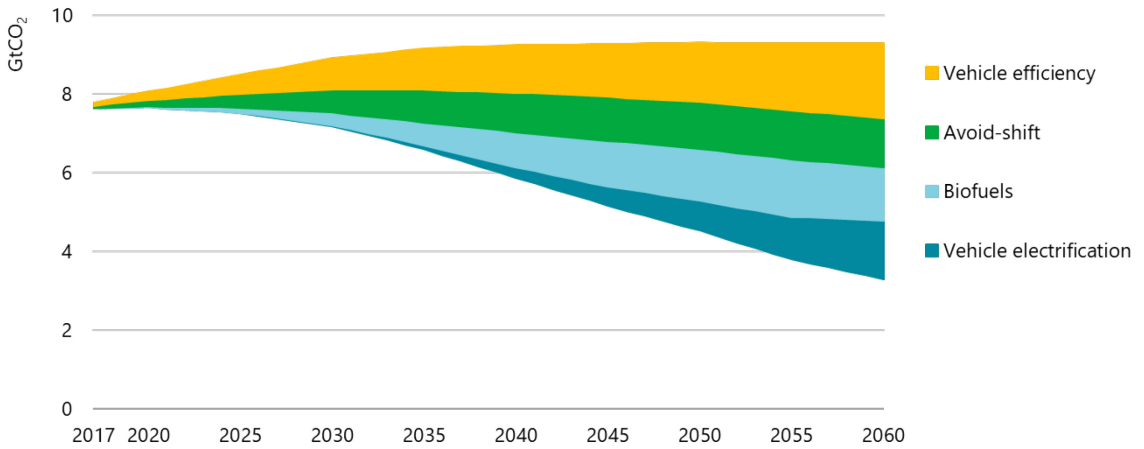
In the CTS, buildings sector cumulative emissions to 2060 are halved relative to the RTS owing to energy efficiency, fuel switching and power sector decarbonisation measures.

In the RTS, final energy demand in the **transport sector** continues rising rapidly, by nearly 40% in 2060 compared to the 2017 level. The largest increase will come from passenger road transport, as rising incomes cause consumers in emerging economies to prefer the convenience and comfort of private cars versus other modes. This leads the projected number of vehicles to nearly double over the next 40 years. Oil remains the dominate fuel, although its share is projected to decline to about 80% by 2060 as the shares of electricity (9%), biofuels (7%) and natural gas (5%) rise, supported by policies to address local air pollution.

Under the CTS, improvements in efficiency combined with rapid transition towards low- and zero-carbon fuels help to curb overall transport energy demand, which falls by approximately 10% in 2060 relative to 2017. Electrification of light-duty vehicles, buses, and two- and three-wheelers leads the share of electricity in transport final energy demand to reach over 25% by 2060, from just over 1% in 2017. The share of biofuels sees the largest increase, reaching nearly 30% by 2060. It will be particularly important in helping to decarbonise long-range transport such as aviation, trucking and shipping. Oil's share falls by nearly 50 percentage points, to about 45% from over 90% today. In the CTS, the difficult-to-decarbonise transport sectors of shipping, aviation and trucking maintain oil as the largest fuel source.

Transport-related direct CO_2 emissions in the CTS decline by nearly 60% of their 2017 level, reaching 3.3 Gt in 2060, and are 65% less than in the RTS. A combination of measures leads to cumulative direct CO_2 reductions in transport of approximately 140 Gt CO_2 by 2060 (Figure 49). Vehicle efficiency measures accrue the largest savings. As electric vehicles are adopted at faster rates than in the RTS, the contribution of efficiency gains from hybrid- and pure-electric powertrains accounts for over one-third of cumulative emissions reduction. Biofuels and avoid-shift measures (which include avoided demand and modal shifting)[32] account for 25% (biofuels) and 27% (avoid-shift measures) of the cumulative emissions reduction between the RTS and CTS. The remaining 13% reduction is attributed directly to vehicle electrification.

Figure 49. Transport sector global direct CO_2 emissions reduction in the CTS relative to the RTS



Note: Analysis above uses the Energy Technology Perspectives modelling framework.

Transport emissions could be cut in half by 2060 with efficiency, electrification, biofuels, and avoid and shift strategies.

[32] Avoid-shift measures are those that result in fewer and shorter trips, increased public transport use, and adoption of non-motorised transport solutions (e.g. walking and cycling). Fiscal policies that make car and air travel more expensive reduce the volume of discretionary trips and lead to more-efficient use of resources (e.g. through trip-chaining or strategic vehicle choice). Smart urban planning can avoid the need to rely on motorised vehicles through mixed-use and transit-oriented development and by planning multicentric cities. Together with densification, these measures can reduce the annual distances travelled by road vehicles. Infrastructure planning and policies that promote convenient, accessible, reliable and attractive public transport, as well as walking and cycling alternatives to cars, can similarly shift transport activity to modes with lower energy and emissions intensities. Similar shifts can be realised in freight. Note that autonomous vehicle uptake is not considered, although it may be in future modelling work.

Annex II. Energy Technology Perspectives modelling framework

This analysis applies a combination of backcasting and forecasting over each scenario to 2060. Backcasting lays out plausible pathways to a desired end state. It makes it easier to identify milestones that need to be reached or trends that need to change promptly for the end goal to be achieved. The advantage of forecasting, where the end state is a result of the analysis, is that it allows greater consideration of short-term constraints.

The analysis and modelling aim to identify an economical way for society to reach the desired outcome. However, the scenario results do not necessarily reflect the least-cost ideal, for a variety of reasons. Many subtleties cannot be captured in a cost-optimisation framework, such as political preferences, feasible ramp-up rates, capital constraints and public acceptance. For the end-use sectors (buildings, transport and industry), doing a pure least-cost analysis is difficult and not always suitable. Long-term projections inevitably contain significant uncertainties, and many of the assumptions underlying the analysis are likely to be inaccurate. Another important caveat to the analysis is that it does not account for secondary effects resulting from climate change such as adaptation costs. By combining varied modelling approaches that reflect the realities of the given sectors, together with extensive expert consultation, this analysis obtains robust results and in-depth insights.

Achieving the Clean Technology Scenario (CTS) and the Limited CO_2 Storage scenario variant (LCS) does not depend on the appearance of unforeseen breakthrough technologies. All technology options introduced in this analysis are already commercially available or at a stage of development that makes commercial-scale deployment possible within the scenario period.[33] Costs for many of these technologies are expected to fall over time, making a low-carbon future economically feasible.

The analysis takes into account those policies that have already been implemented or decided. In the short term, this means that deployment pathways may differ from what would be most cost-effective. In the longer term, the analysis emphasises a normative approach, and fewer constraints governed by current political objectives apply in the modelling. The objective of this methodology is to provide a model for a cost-effective transition to a sustainable energy system.

To make the results more robust, the analysis pursues a portfolio of technologies within a framework of cost minimisation. This offers a hedge against the real risks associated with the pathways. If one technology or fuel fails to fulfil its expected potential, it can more easily be compensated by another if its share in the overall energy mix is low. The tendency of the energy system to comprise a portfolio of technologies becomes more pronounced as carbon emissions are reduced. This is because the technology options for emissions reduction and their potential typically depend on the local conditions in a country. However, uncertainties may become larger, depending on the level of maturity of a given technology and the risk of not reaching expected technological development targets.

[33] See the "Technology approach" section for more information on the technologies considered in this analysis.

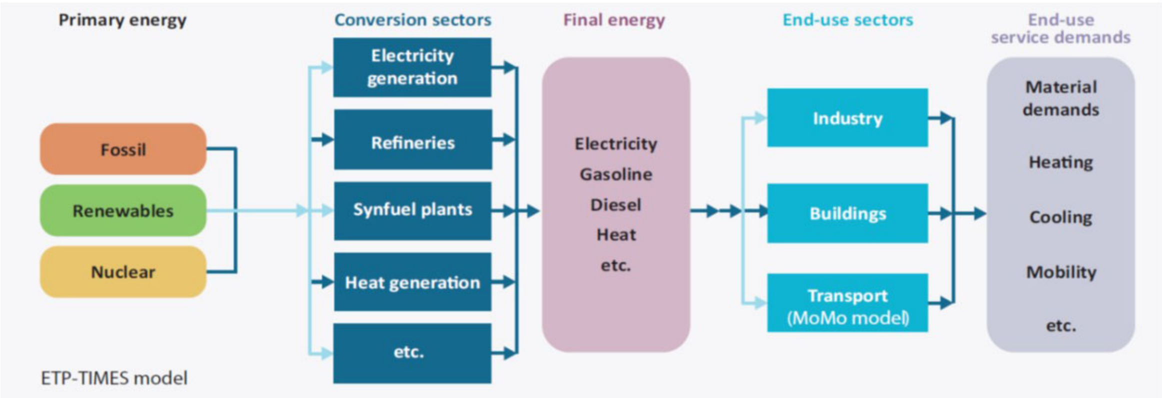
Combining analysis of energy supply and demand

The Energy Technology Perspectives (ETP) modelling framework, which is the primary analytical tool used in this analysis, supports integration and manipulation of data from four soft-linked models:

- energy conversion
- industry
- transport
- buildings (residential and commercial/services).

It is possible to explore outcomes that reflect variables in energy supply (using the energy conversion model) and in the three sectors that have the greatest demand and hence the largest emissions (using models for industry, transport and buildings). The following schematic illustrates the interplay of these elements in the processes by which primary energy is converted to the final energy that is useful to these demand-side sectors (Figure 50).

Figure 50. Structure of the ETP model



Note: MoMo = IEA Mobility Model.

The ETP model enables a technology-rich, bottom-up analysis of the global energy system.

ETP-TIMES supply model

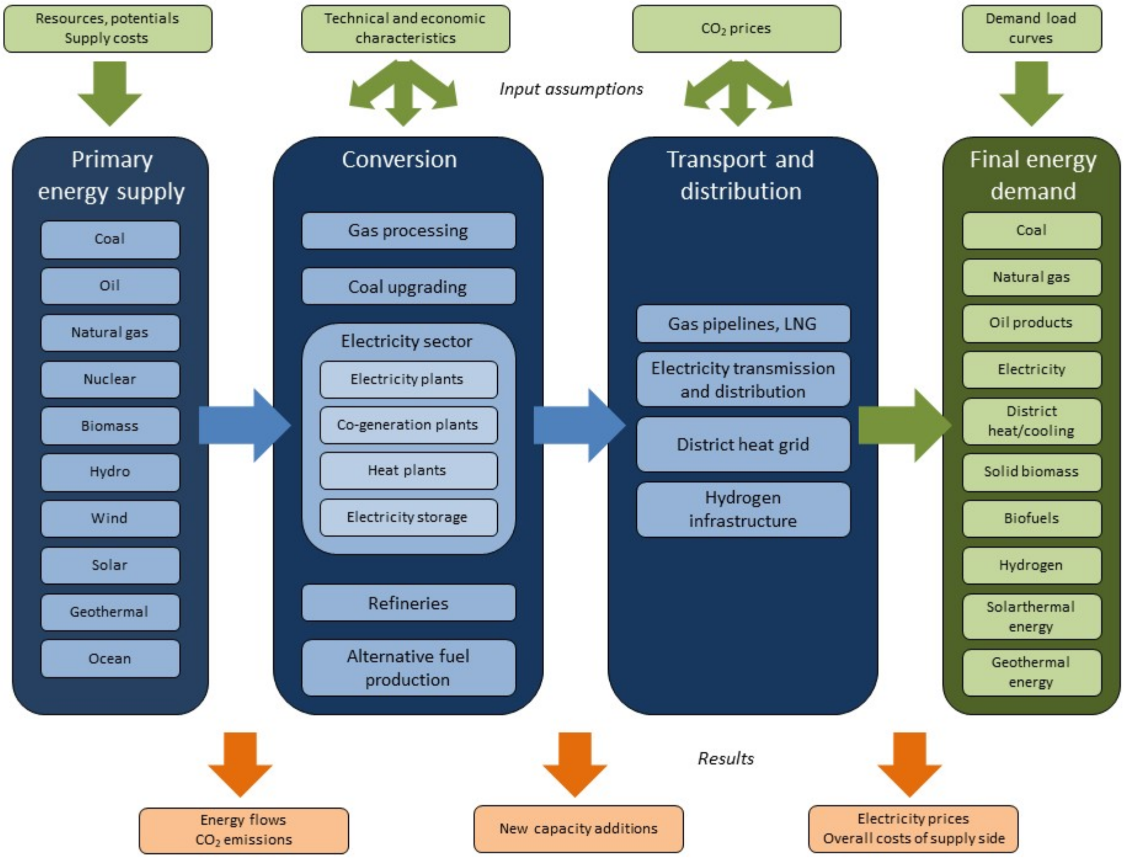
The global ETP-TIMES supply model is a bottom-up, technology-rich model that depicts a technologically detailed supply side of the energy system. It models from primary energy supply and conversion to final energy demand up to 2060. It is based on the TIMES (The Integrated MARKAL-EFOM System) model generator, which was developed by the Energy Technology Systems Analysis Programme Technology Collaboration Programme[34] of the International Energy Agency (IEA), and allows an economic representation of local, national and multiregional energy systems on a technologically detailed basis (Loulou et al., 2005).

[34] For further information on the TIMES model generator, its applications and typical energy technology input data assumptions see the ETSAP website (www.iea-etsap.org).

The model covers 28 regions, representing either individual countries, such as the People's Republic of China ("China") or India, or aggregates of several countries, such as the Association of Southeast Asian Nations (ASEAN). The model regions are linked by trade in fossil fuel energy carriers (crude oil, petroleum products, coal, pipeline gas or liquefied natural gas [LNG]), biofuels (biodiesel and bioethanol) and electricity.

Starting from the current situation in the conversion sector (e.g. existing capacity stock, operating costs and conversion efficiencies), the model integrates the technical and economic characteristics of existing technologies that can be added to the energy system. The model can then determine the least-cost technology mix needed to meet the final energy demand calculated in the ETP end-use sector models for agriculture, buildings, industry and transport (Figure 51).

Figure 51. Structure of the ETP-TIMES supply model



Notes: CO_2 = carbon dioxide; *co-generation* refers to the combined production of heat and power.

ETP-TIMES determines the least-cost strategy using supply-side technologies and fuels to cover the final energy demand from the end-use sector models.

Technologies are described by their technical and economic parameters such as conversion efficiencies or specific investment costs. Learning curves are used for new technologies to link future cost developments with cumulative capacity deployment. Overall, around 550 technologies are considered in the conversion sector. Electricity demand is divided into non-urban and urban. Urban is further divided into five city classes by population size to reflect local differences in the technical potential for rooftop solar photovoltaics (PVs) and municipal solid waste (IEA, 2016a; IEA, 2016b). Renewable energy sources – onshore and offshore wind, solar PVs and solar thermal electricity (STE) – are differentiated according to their potential, based on their capacity factor (in addition to offshore wind by water depth and distance to the coast) and by their distance to the city classes (five distance categories) as an approximation for the transmission costs needed to use these resources. The ETP-TIMES supply model also takes into account additional constraints in the energy system (e.g. emissions reduction goals). Its results provide detailed information on future energy flows and their related emissions impact, required technology additions and the overall cost of the supply-side sector.

To capture the impact on investment decisions of variations in electricity and heat demand, as well as the variation in generation from certain renewable technologies, a year is divided into four seasons. Each season is represented by a typical day, which is divided into 8 daily load segments of 3 hour durations.

For a more detailed analysis of the operational aspects of the electricity sector, the long-term ETP-TIMES supply model has been supplemented with a linear dispatch model. This model uses the outputs of the ETP-TIMES supply model to generate the electricity capacity mix for a specific model region and year. This allows for detailed analysis of an entire year with 1 hour time resolution using datasets for wind production, solar PV production and hourly electricity demand.

Given the hourly demand curve and a set of technology-specific operational constraints, the model determines the optimal hourly generation profile. To increase the flexibility of the electricity system, the linear dispatch model can invest in electricity storage or additional flexible generation technologies (e.g. gas turbines). Demand response from electricity use in the transport and buildings sectors is a further flexibility option included in the dispatch model analysis.

This linear dispatch model represents storage in terms of three steps: charge, store and discharge. The major operational constraints included in the model are capacity states, minimum generation levels and time, ramp-up and -down, minimum downtime hours, annualised plant availability, cost considerations associated with start-up and partial-load efficiency penalties, and maximum storage reservoir capacity in energy terms (megawatt hours [MWh]).

Model limitations include challenges associated with a lack of comprehensive data on storage volume (MWh) for some countries and regions. Electricity networks are not explicitly modelled, which precludes the study of the impact of spatially dependent factors, such as the aggregation of variable renewable outputs with better interconnection.

ETP-TIMES industry model

For the purposes of the industry model, the industrial sector includes International Standard Industrial Classification (ISIC) Divisions 7, 8, 10-18, 20-32 and 41-43, and Group 099, covering mining and quarrying (excluding mining and extraction of fuels), construction and manufacturing. Petrochemical feedstock use and blast furnace and coke oven energy use are also included within the boundaries of industry.

Industry is modelled using TIMES-based linear optimisation models for five energy-intensive sectors (iron and steel, chemicals and petrochemicals, cement, pulp and paper, and aluminium).

These five submodels characterise the energy performance of process technologies from each of the energy-intensive subsectors, covering 39 countries and regions. Typically, raw material production is not included within the boundaries of the TIMES models, except for the iron and steel sector, in which energy use for coke ovens and blast furnaces is covered. Due to the complexity of the chemicals and petrochemicals sector, the technology detail of the submodel focuses on five products that represent about 46% of the sector's energy use:[35] ethylene; propylene; benzene, toluene and xylene (BTX); ammonia; and methanol. The remaining industrial final energy consumption is accounted for in a simulation model that estimates energy consumption based on activity level.

In the Reference Technology Scenario (RTS), demand for materials for the duration of the model time horizon is an exogenous input to the model. It is estimated based on country or regional-level data for gross domestic product (GDP), disposable income, short-term industrial capacity, current materials consumption, regional demand saturation levels derived from historical demand intensity curves, and resource endowments, along with some degree of improvement in recycling collection rates assuming a continuation of current trends (Figure 52). Total production is simulated by factors such as process, age structure (vintage) of plants and stock turnover rates.

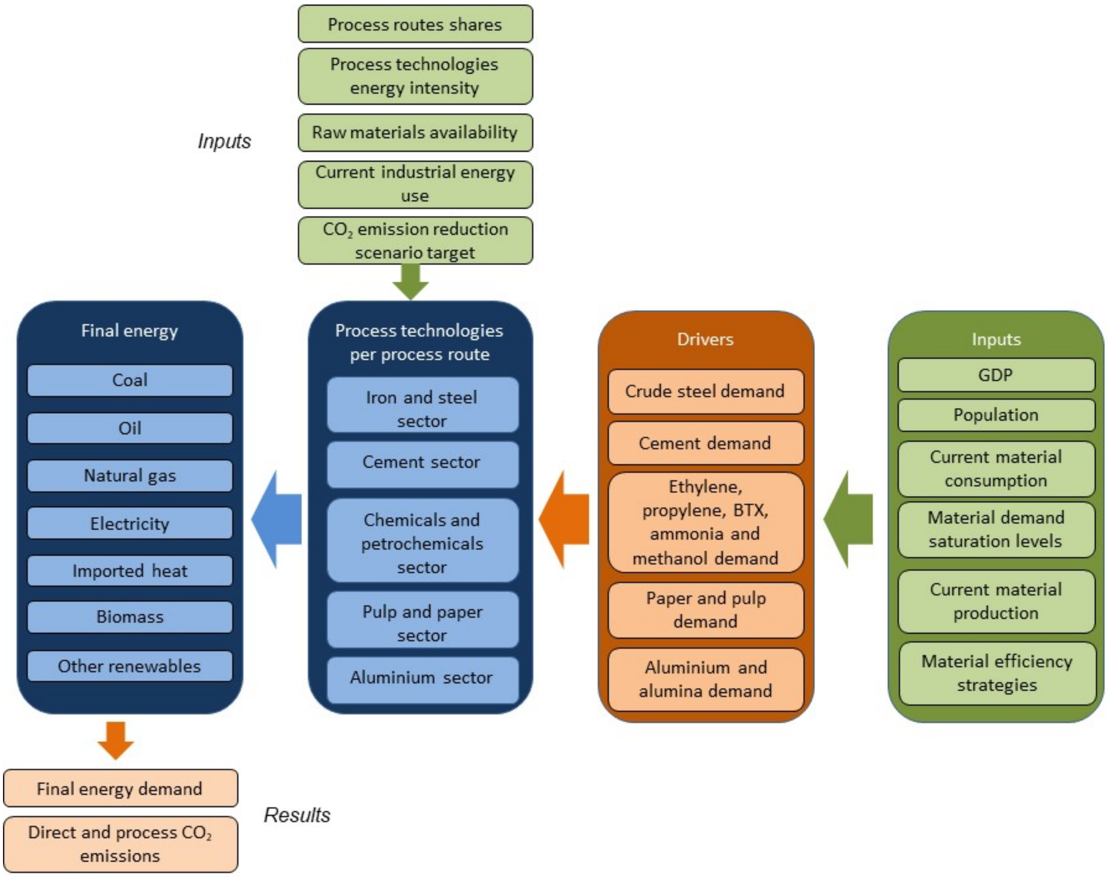
In the CTS and LCS, material efficiency strategies are pursued to a moderate degree, affecting overall production levels for certain materials. Strategies pursued include considerable improvements in manufacturing yields, moderate vehicle lightweighting, limited uptake of improved buildings design and construction, and limited improvements in metals reuse. These scenarios also consider changes in materials demand due to use-phase technology shifts, including buildings lifetime extension resulting from energy retrofits and reduced vehicle use. For further details on material efficiency strategies applied in the CTS, see IEA (2019).

Each industry submodel is designed to account for sector-specific production routes for which relevant process technologies are modelled. Industrial energy use and technology portfolios for each country or region are characterised in the base year using relevant energy use and material production statistics for each energy-intensive industrial subsector. Changes in the technology and fuel mix, as well as efficiency improvements, are driven by exogenous assumptions on the penetration and energy performance of best available technologies (BATs), constraints on the availability of raw materials, techno-economic characteristics of the available technologies and process routes, and assumed progress on demonstrating innovative technologies at commercial scale. Thus, the results are sensitive to assumptions on how quickly physical capital is turned over, on relative costs of the various technology options and fuels, and on incentives for the use of BATs for new capacity. Fuel costs are based on outputs from the ETP conversion sector model.

The industry model allows analysis of different technology and fuel-switching pathways in the sector to meet projected material demands within a given related CO_2 emissions envelope in the modelling horizon and in least-cost fashion.

[35] Including energy use as petrochemical feedstock.

Figure 52. Structure of ETP industry model



Based on socio-economic assumptions, historical trends, expert views and statistical information, exogenous material demand projections are used to determine the final energy consumption and direct CO_2 emissions of the sector, depending on the energy performance of process technologies and technology choice within each of the available production routes.

Global buildings sector model

The buildings sector is modelled using a global simulation stock accounting framework, split into residential and non-residential subsectors across 35 countries and regions (Figure 53). The residential subsector includes all energy-using activities in apartments and houses, including space and water heating, cooling, ventilation, lighting, and the use of appliances and other electrical plug loads. The non-residential subsector includes activities related to trade, finance, real estate, public administration, health, food and lodging, education and other commercial services. This is also commonly referred to as the commercial and public services sector. It covers energy used for space and water heating, cooling, ventilation, lighting and a range of other miscellaneous energy-consuming equipment such as commercial appliances, office equipment, cooking devices and medical equipment.

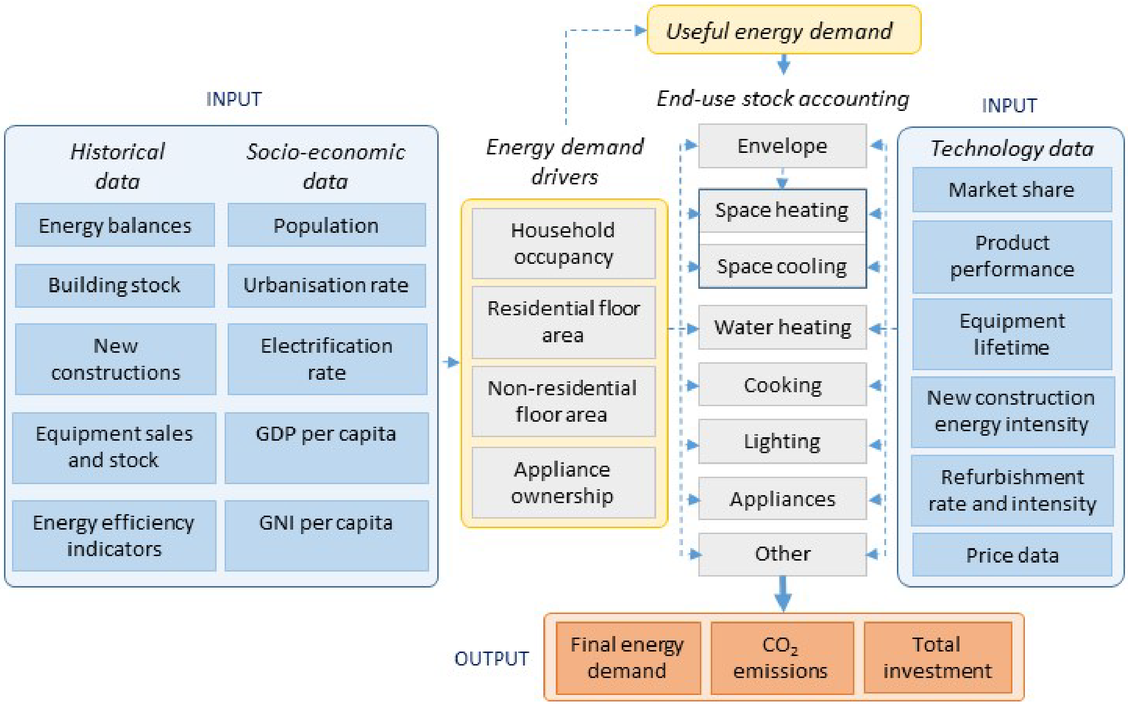
For both subsectors, the model uses socio-economic drivers, such as population, GDP, income (approximated by gross national income [GNI] per capita), urbanisation and electrification rates, to project the major buildings energy demand drivers, including residential and non-residential floor area, number of households and residential appliance ownership. As far as possible, country statistics are used for historical energy balances by end use, floor area, appliance ownership rates, and other building-related technical data and efficiency rates (e.g. technology stock and sales data). These data can be difficult to obtain across many developing countries. Therefore, in several cases, the historical driver parameters for the ETP buildings sector model have been estimated using a series of applied logistic functions relative to GDP, GNI per capita, urbanisation and electrification, or another combination of proxies as defined by multilinear regressions. Those functions are applied to individual countries, or, in cases where few data are available, to country clusters designed to be as homogeneous as possible within the cluster and as heterogeneous as possible among cluster categories. The functions differentiate the applied energy indicators by year to 2060 and across the 35 model countries and regions. The indicators are then applied within a stock accounting framework, which is distinguished by annual vintages, and the technology (or buildings stock) lifetimes are spread using a Weibull distribution.

Whenever possible, historical data and buildings sector information, such as buildings energy codes or minimum energy performance standards for end-use equipment, are applied within the model. Depending on the end use or technology, multiple categories are included (or estimated) within the model. For example, the global buildings stock is broken down into three categories, including near-zero energy buildings (nZEBs), code-compliant buildings and buildings that do not meet a code or do not have an applicable buildings energy code. Buildings end-use technologies (e.g. major household appliances) are similarly broken down into categories where applicable, such as best in class, median market performance and minimum energy performance technologies.

Using the annually differentiated stock accounting framework by country or region, historical useful energy intensity is estimated across the various buildings end uses based on assumed technology shares and efficiencies. Buildings stock characteristics (e.g. nZEB and code-compliant buildings energy intensity) are applied with heating and cooling equipment to estimate historical and then projected annual demand for space heating and cooling per unit of floor area (i.e. useful energy services delivered). The model also takes into account the ageing, refurbishment or reconstruction of buildings through degradation, improvement, renovation rates or specific lifetime distributions. For the other end uses (e.g. water heating, lighting, appliances and cooking), the useful energy demand is similarly estimated through a differentiated stock accounting framework to determine the useful (or delivered) energy service by end use. Across all end uses and countries/regions, useful energy demand can vary over time (e.g. relative to average GNI per capita growth), where some convergence (in useful energy service) is assumed across similar countries/regions, depending on the buildings ETP scenario.

For each of the derived useful energy demands, a suite of technology and fuel options are represented in the model reflecting current techno-economic characteristics (e.g. efficiencies, costs and lifetimes) as well as their assumed evolution to 2060 in the applied ETP scenario. Depending on the technology stock, as well as assumptions on the penetration and market share of new technologies in the future, the ETP buildings sector model allows exploration of strategies that meet the different useful energy demands and the quantification of the resulting developments by final energy consumption and related CO_2 emissions. Detailed annual results from the model are also applied within a logarithmic mean Divisia index analysis. This allows in-depth tracking of changes in activity, technology and energy performance over time with respect to the various scenarios.

Figure 53. Structure of the buildings sector model



Starting from socio-economic assumptions, the buildings sector model determines demand drivers and related useful energy demands, which are then applied across buildings end uses and technology choices to calculate final energy consumption across the 35 model countries and regions.

Modelling of the transport sector in the MoMo

Overview

The MoMo is a techno-economic database spreadsheet and simulation model that enables detailed projections of transport activity, vehicle activity, energy demand, and well-to-wheel CO_2 and pollutant emissions according to user-defined policy scenarios to 2060.

It comprises:

- 27 countries and regions, which are aggregated into four Organisation for Economic Co-operation and Development (OECD) regional clusters and 11 groups of non-OECD economies
- historical data from 1975 to 2017 (or 1990 to 2017 for certain countries)
- a simulation model in five-year time steps, for creating scenarios to 2060 based on "what-if" analysis and backcasting
- disaggregated urban versus non-urban vehicle stock, activity, energy use and emissions
- all major motorised transport modes (road, rail, shipping and air) providing passenger and freight services

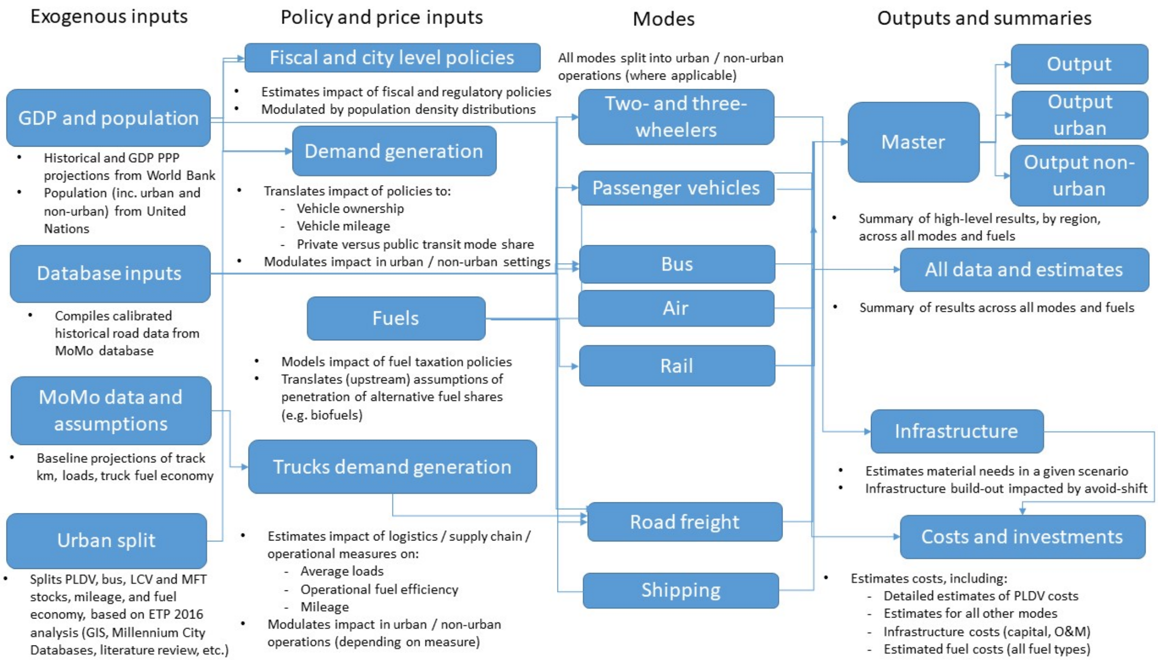
- a wide range of powertrain technologies: internal combustion engines (including gasoline, diesel, compressed natural gas [CNG] and LNG), as well as hybrid electric and electric vehicles (including plug-in hybrid electric and battery-electric vehicles) and fuel-cell electric vehicles.

Associated fuel supply options include: gasoline and diesel, biofuels (ethanol and biodiesel via various production pathways) and synthetic alternatives to liquid fuels (coal to liquid and gas to liquid); gaseous fuels, such as natural gas (CNG and liquefied petroleum gas) and hydrogen via various production pathways; and electricity (with emissions according to the average national generation mix as modelled by the ETP-TIMES model in the relevant scenario).

The MoMo further enables estimation of scenario-based costs of vehicles, fuels and transport infrastructure, as well as the primary material inputs required for the construction of vehicles, related energy needs and the resultant CO_2 emissions.

To ease the manipulation and implementation of the modelling process, the MoMo is split into modules that can be updated and elaborated upon independently. Figure 54 shows how the modules interact with one another. By integrating assumptions on technology availability and cost in the future, the model reveals, for example, how costs could drop if technologies were deployed at a commercial scale and allows detailed bottom-up "what-if" modelling, especially for passenger light-duty vehicles (PLDVs) and trucks (IEA, 2018).

Figure 54. Structure of the MoMo



Notes: PPP = purchasing power parity; km = kilometres; LCV = light commercial vehicle; MFT = medium freight truck; GIS = geographic information system; O&M = operation and maintenance.

The MoMo covers all transport modes and includes modules on local air pollutants and the cost of fuels, vehicles and infrastructure, as well as analysis of the material needs for new vehicles.

Data sources

The MoMo modelling framework relies upon compiling and combining detailed data from various sources on vehicles in each of the countries/regions to estimate aggregate energy consumption, emissions and other energy-relevant metrics at the country/regional level.

MoMo modellers have collected historical data series from a variety of public and proprietary data sources for more than a decade. National data are gathered primarily from the following organisations: 1) national and international public institutions (e.g. the World Bank, the Asian Development Bank and Eurostat); 2) national government ministries (e.g. departments of energy and transport, and statistical bureaus); 3) federations, associations and non-governmental organisations (e.g. Japan Automobile Manufacturers Association, Korea Automobile Manufacturers Association and National Association of Automobile Manufacturers of South Africa); 4) public research institutions (e.g. from peer-reviewed papers and reports from universities and national laboratories); 5) private research institutions (e.g. International Council on Clean Transportation); and 6) private business and consultancies (e.g. IHS Automotive/Polk, Segment Y, and other major automotive market research and analysis organisations, in addition to major energy companies and automobile manufacturers).

Calibration of historical data with energy balances

The framework for estimating average and aggregate energy consumption for a given vehicle class *i* can be neatly summarised by the Activity = Share x Intensity x Fuel (ASIF) identity (Schipper, Marie-Lilliu and Gorham, 2000):

$$\boldsymbol{F} = \sum_{i} \boldsymbol{F}_i = \boldsymbol{A} \sum_{i} \left(\frac{\boldsymbol{A}_i}{\boldsymbol{A}}\right)\left(\frac{\boldsymbol{F}_i}{\boldsymbol{A}_i}\right) = \boldsymbol{A} \sum_{i} \boldsymbol{S}_i \boldsymbol{I}_i = \boldsymbol{F}$$

where *F* is the total fuel use (megajoules [MJ] per year); *A* is the vehicle activity (vehicle kilometres [vkm] per year]); *I* is the energy intensity (MJ/vkm); *S* is the structure (shares of vehicle activity [%]); and *i* is an index of vehicle modes and classes (MoMo vehicles belong to several modes). Vehicle activity can also be expressed as the product of vehicle stock (vehicles) and mileage (kilometre [km] per year). The energy used by each mode and vehicle class in a given year (MJ per year) can therefore be calculated as the product of three main variables: vehicle stock (vehicles), mileage (km/year) and fuel economy (MJ/vkm).

To ensure a consistent modelling approach is adopted across the modes, energy use is estimated based on stocks (via scrappage functions), utilisation (travel per vehicle), consumption (energy use per vehicle, i.e. fuel economy) and emissions (via fuel emissions factors for CO_2 and pollutants on a vehicle and well-to-wheel basis) for all modes. Final energy consumption, as estimated by the "bottom-up" approach described above, is then validated against and calibrated as necessary to IEA energy balances (IEA, 2016c).

Vehicle platform, components and technology costs

Detailed cost modelling for PLDVs accounts for initial (base year) costs, asymptotic (i.e. fully learned-out) costs and an experience parameter that defines the shape of cost reductions. These three parameters define learning functions that are based on the number of cumulative units produced worldwide. Cost functions define various vehicle configurations, including vehicle component efficiency upgrades (e.g. improved tyres or air-conditioning controls), material substitution and vehicle downsizing, conventional spark and compression ignition engine improvements, conventional and plug-in hybrid powertrain configurations, batteries, electric motors and fuel cells. These configurations are added to a basic glider cost. The ratios of differences in vehicle technologies deployed in PLDVs are extrapolated to other road vehicle types (i.e. two- and three-wheelers and freight trucks).

The primary drivers of technological change in transport are assumptions on the cost evolution of the technology, and the policy framework incentivising adoption of the technology. Oil prices and the set of policies assumed can significantly alter technology penetration patterns. The model supports a comparison of marginal costs of technologies and aggregates to total cost across all modes and regions, for each scenario.

Infrastructure and fuel costs

The MoMo estimates future infrastructure costs according to scenario-based projections on modal activity and fuel use. Infrastructure cost estimates include capital costs, operations and maintenance, and reconstruction costs – split by geography into urban and non-urban regions according to the location of the investments. Fuel costs are also estimated based on scenario-specific projections of urban and non-urban consumption, and include all fuel types (fossil-derived fuels, biofuels, electricity and hydrogen).

Elasticities

The MoMo has included key elasticities from 2012. Price and income elasticities of fuel demand, for light-duty (passenger) road activity as well as road freight, based upon representative "consensus" literature values, are used to model vehicle activity and fuel consumption responses to changes in fuel prices. These fuel prices are driven by projections and policy scenarios (CO_2 or fuel taxes). Elasticities also enable vehicle ownership to vary according to fuel prices and income, as proxied by GDP per capita.

Framework assumptions

Economic activity (Table 2) and population (Table 3) are the two fundamental drivers of demand for energy services in scenarios. These are kept constant across all scenarios as a means of providing a starting point for the analysis and facilitating interpretation of the results. Under the ETP assumptions, global GDP will more than triple between 2017 and 2060; however, uncertainty around GDP growth across the scenarios is significant. CO_2 emissions in the RTS are substantially higher than the level that would be needed to keep warming with 1.5 to 2 degrees Celsius. The resulting climate change in the RTS is likely to have a profound and unpredictable impact on the potential for economic growth. This effect is not captured by ETP analysis. Moreover, the structure of the economy is likely to have non-marginal differences across scenarios, suggesting that GDP growth is unlikely to be identical even without considering the climate impact. The redistribution of financial, human and physical capital will affect the growth potential globally and on a regional scale.

Energy prices, including those of fossil fuels, are a central variable in the analysis. The continuous increase in global energy demand is translated into higher prices for energy and fuels. Rising prices are a likely consequence unless current demand trends are broken. However, the technologies and policies to reduce CO_2 emissions in the scenarios will have a considerable impact on energy demand, particularly for fossil fuels. Declining demand for oil in the CTS and LCS reduces the need to produce oil from costly fields higher up the supply curve, particularly in non-members of the Organization of the Petroleum Exporting Countries. As a result, oil prices in these scenarios are lower than in the RTS and even decline. Prices for natural gas will also be affected, directly through downward pressure on demand, and indirectly through the link to oil prices that often exists in long-term gas supply contracts.[36] Coal prices are also substantially lower owing to the large shift away from coal in the CTS and LCS.

Table 2. Real GDP growth projections used in the analysis, %

Country/region	2015-20	2020-30	2030-40	2040-60	2015-60
World	3.7	3.6	3.1	2.1	2.8
OECD	2.2	1.8	1.7	1.6	1.7
Non-OECD	4.8	4.8	3.8	2.3	3.5
ASEAN	5.2	4.9	3.7	2.2	3.5
Brazil	0.9	2.7	3.0	1.7	2.1
China	6.5	5.0	3.3	1.7	3.3
European Union	2.2	1.6	1.4	1.3	1.5
India	7.4	7.3	5.2	2.8	4.8
Mexico	2.7	3.2	3.0	2.1	2.6
Russian Federation	1.3	1.9	2.1	1.2	1.5
South Africa	1.4	2.3	2.9	2.2	2.3
United States	2.2	1.8	2.0	1.9	1.9

Notes: Growth rates are compounded average annual growth rates. They are based on GDP in United States dollars in purchasing power parity constant 2015 terms. GDP is assumed to be identical across scenarios.

Sources: IEA (2016d), *World Energy Outlook* 2016; IMF (2016), *World Economic Outlook Database*, www.imf.org/external/pubs/ft/weo/2016/01/weodata/index.aspx.

Table 3. Population projections used in the analysis (millions)

Country/region	2015	2020	2030	2040	2050	2060
World	7 348	7 761	8 515	9 172	9 733	10 184
OECD	1 275	1 310	1 360	1 395	1 413	1 420
Non-OECD	6 073	6 452	7 154	7 778	8 320	8 764
ASEAN	632	666	724	766	793	805
Brazil	206	214	225	232	233	229
China	1 379	1 407	1 424	1 401	1 349	1 274
European Union	510	514	516	513	506	495
India	1 309	1 383	1 513	1 605	1 659	1 679
Mexico	121	128	142	151	158	160
Russian Federation	144	144	141	136	133	130
South Africa	55	59	64	69	73	75
United States	322	334	357	376	392	407

Source: UNDESA (2015), *World Population Prospects: The 2015 Revision*, https://esa.un.org/unpd/wpp/.

[36] This link is assumed to become weaker over time in the ETP analysis, as the price indexation business model is gradually phased out in international markets.

Technology approach

In this analysis, the definition of technologies "available and in the innovation pipeline" includes those technologies that are commercially available, or at the stage of development that makes commercial-scale deployment possible within the 2020-60 scenario period, such as:

- Existing commercial BATs, for example, solar thermal and heat pumping technologies for space and water heating, light-emitting diodes (LEDs) for lighting, high-performance windows (e.g. low-emissivity and double- or triple-glazed windows), high-performance insulation, green or cool roofs, thermal energy storage, enhanced catalytic and biomass-based processes for chemical production, onshore wind, offshore wind, solar PVs, STE, hydropower, geothermal (direct, flash), nuclear power, large-scale electric heat pumps, and conventional biodiesel and bioethanol.
- Technologies in the demonstration phase (technologies that have been proven, and have sufficient techno-economic data available to be assumed to be commercially available within the time horizon of the model), for example, high-performance heat pumping technologies, high-efficacy (e.g. greater than 150 lumens/watt) LED lighting, aerosol-based whole-building envelope air sealing, advanced buildings insulation (aerogel, vacuum insulated panel and phase change materials), whole-building renovation solutions, zero-emission fuels for transport, upgraded smelt reduction and direct reduced iron, coal-fired integrated gasification combined cycle (IGCC), coal-fired IGCC with CO_2 capture, coal-fired power plants with post-combustion CO_2 capture, conventional bioethanol with CO_2 capture, advanced biodiesel, large-scale hydrogen electrolysis and hydrogen from natural gas with CO_2 capture.
- Technologies in pilot testing, for example, "smart" buildings technologies and intelligent controls, dynamic solar control, hybrid heat pumps, fuel cells and hydrogen-ready equipment, inert anodes for aluminium smelting, oxy-fuelled coal power plants with CO_2 capture, gas-fired power plants with CO_2 capture, biomass integrated gasification combined cycle (BIGCC), wave energy, tidal stream, tidal lagoon, enhanced geothermal energy systems, advanced biodiesel with CO_2 capture, hydrogen from biomass gasification and biofuels from algae.
- Technologies under development, for example, solar cooling solutions, vacuum insulated panels for refrigeration and buildings envelopes, thermoelectric cooling using heat pumps, full oxy-fuelling kilns for clinker production, BIGCC with CO_2 capture, and hydrogen from coal and biomass with CO_2 capture.
- Technologies with incremental improvements of performances compared with today's BATs (may not be available yet, but can be envisaged to be available within the time frame of scenarios), for example, high-performance appliances in buildings, improved controls of cooling and heating (smart thermostats), advanced district energy networks, low rolling resistance tyres, vehicle design improvements that reduce energy needs and energy intensity improvements towards BAT in industrial process technologies.
- Supporting infrastructure to facilitate the uptake of improved and newly demonstrated technologies, for example, low-temperature distribution, high-performance district energy networks, smart grids with intelligent demand-side response, transport and storage infrastructure to support carbon capture and storage, and electric vehicle charging infrastructure.

Some technology options are not available within the model until later time periods, depending on their current level of readiness, and some have constraints to account for process-specific limitations to deployment.

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Abbreviations and acronyms

ASEAN	Association for Southeast Asian Nations
BCSA	belite calcium sulphoaluminate
BECCU	bioenergy with carbon capture and use
BECCS	bioenergy with carbon capture and storage
BF	blast furnace
BIGGC	biomass integrated gasification combined-cycle
BOF	basic oxygen furnace
CACS	carbonation of calcium silicates
CAPEX	capital expenditure
CCS	carbon capture and storage
CCU	carbon capture and utilisation
CCUS	carbon capture, utilisation and storage
CDR	carbon dioxide removal
CFB	circulating fluidising bed
CO	carbon monoxide
CO_2	carbon dioxide
CO_2-EOR	carbon dioxide enhanced oil recovery
CSA	calcium sulphoaluminate
CTS	Clean Technology Scenario
DACCS	direct air carbon capture and storage
DRI	direct reduced iron
EAF	electric arc furnace
EOR	enhanced oil recovery
ETP	Energy Technology Perspectives
FLH	full load hours
FT	Fischer-Tropsch

H_2	hydrogen
HHV	higher heating value
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
LED	light-emitting diode
LCS	Limited CO_2 Storage scenario variant
LHV	lower heating value
LPG	liquefied petroleum gas
MOMS	magnesium oxide derived from magnesium silicates
PC	Portland cement
PHCS	prehydrated calcium silicates
PLDV	passenger light-duty vehicle
PtG	power-to-gas
PtL	power-to-liquids
PV	photovoltaic
R&D	research and development
RD&D	research, development and demonstration
RTS	Reference Technology Scenario
SNG	synthetic natural gas
TRL	technology readiness level
UR	utilisation rate
USD	United States dollar

Units of measure

EJ	exajoule
g CO_2/kWh	gramme of carbon dioxide per kilowatt hour
GJ	gigajoule
GJ/t	gigajoule per tonne

Gt	gigatonne
Gt CO_2	gigatonne of carbon dioxide
GW	gigawatt
GWh	gigawatt hour
kg	kilogramme
kgH_2	kilogramme of hydrogen
kt	thousand tonnes
kW_e	kilowatt electrical
kWh/t	kilowatt hour per tonne
MBtu	million British thermal units
Mt	million tonnes
Mt CO_2	million tonnes of CO_2
MtH_2	million tonnes of hydrogen
MW	megawatt
MW_e	megawatt electrical
MWh	megawatt hour
PJ	petajoule
pkm	passenger kilometre
PWh	petawatt hour
t	tonne
tCO_2	tonne of CO_2
TWh	terawatt hour
vkm	vehicle kilometre

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