THINK Economic and Financial Analysis

Energy Outlook 2024: High ambitions, steadier speeds

January 2024

From the impact of ongoing geopolitical volatility on commodity markets to current challenges facing global renewable power deployment, 2024 is set to be mixed year for the energy sector. But even as the speed of progress begins to settle, we point to a few positive developments and silver linings along the energy transition pathway.

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Energy markets are better supplied

Both the oil and gas market are set to be more comfortable than originally anticipated this year. Strong non-OPEC+ supply growth has shrunk the size of the oil deficit in 2024, while for natural gas, European storage is set to finish the season well above average, suggesting limited upside for prices

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Oil to edge higher but gains to be modest

The bullish outlook for the oil market has softened in recent months, given stronger-than-expected supply growth from non-OPEC producers in 2023. This was predominantly driven by the US. However, growth was also seen from Brazil, Guyana, and Norway. Stronger non-OPEC supply has meant that OPEC+ has had to take further action to try to keep the market balanced.

Additional voluntary supply cuts announced by a handful of OPEC+ members at the end of 2023 amounted to 2.2m b/d. However, 1.3m b/d was the rollover of existing cuts from Saudi Arabia and Russia, which means that the market sees around 900k b/d of fresh cuts for the first quarter of this year. This action from OPEC+ has ensured that the surplus that was expected in 1Q24 has been erased. However, our balance shows that the market will return to a fairly large surplus in 2Q24 if OPEC+ do not roll over these cuts into the second quarter. We are of the view the group will partially extend current voluntary cuts to ensure the market is more or less balanced in the second quarter and in an attempt to keep prices near US$80/bbl levels, which are around Saudi Arabia's fiscal breakeven.

The issue for OPEC+ is if deeper cuts are needed, as it will be more challenging for members to agree on this. The group is already making significant cuts and recent supply reductions from the group have come in the form of voluntary cuts from a handful of members rather than group-wide cuts, suggesting that members are finding it increasingly more difficult to agree on any reductions. This is also evident with Angola's recent departure from OPEC; it wasn't happy about its production target for 2024, even though the country is unlikely to produce much above its proposed target level.

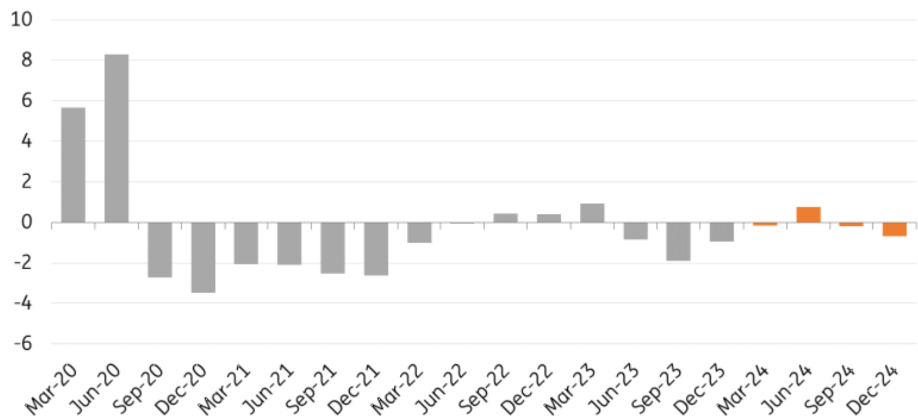
OPEC+ policy will be important for price direction through 2024 and a large part of OPEC+ policy will depend on how demand plays out throughout the year.

For 2024, we expect oil demand to grow in the region of 1m b/d, which would be roughly half of the demand growth achieved in 2023. A slower growth rate should not be surprising, given that the post-Covid demand recovery is now largely behind us. In addition, global GDP growth is set to slow this year, given the scale of monetary tightening we have seen from central banks worldwide. In Europe and the Americas, we expect oil demand to fall year-on-year, while growth will be predominantly driven by Asia and specifically China, which is expected to make up around 70% of global demand growth.

We expect ICE Brent to average US$82/bbl over the course of 2024, with most of the upside likely to be seen over the second half of the year, a period where our balance shows the market to be in deficit. Although, to be fair, the deficit over this period has shrunk in recent months.

Recent developments in the Middle East remain an upside risk to our view on the market. Attacks in the Red Sea have seen a growing number of crude oil and refined product tankers deciding to avoid the region and take a longer route around Southern Africa. Longer voyage times could lead to some tightness in physical markets, but it is important to point out that the rerouting of tankers is not having an impact on oil production. However, the bigger upside risk for the oil market is if tensions in the Middle East spread, which starts to have an impact on oil production or cuts off oil flows that cannot be rerouted. This would be the case if we were to see any disruption around the Strait of Hormuz, which sees in the region of 20m/d of oil moving through it.

Oil market to return to surplus in Q2 without an extension in OPEC+ cuts (m b/d)



Source: ING Research, IEA, EIA, OPEC

European natural gas storage to remain comfortable

The European natural gas market has had a relatively comfortable 2023/24 heating season so far, which puts the market in a good position for the rest of the year. European storage remains well above the 5-year average despite the region having gone through several cold spells this winter.

Our balance sheet shows that Europe should exit this heating season with storage around 52% full compared to a 5-year average of 41% (assuming no demand spikes or supply shocks). This will once again make the job of refilling storage through the summer months a lot more manageable. This suggests that any upside in prices is likely limited. We also expect Europe to go into the 2024/25 heating season with storage well above the European Commission's target of 90% by 1 November. We believe storage will be around 96% full by the end of October.

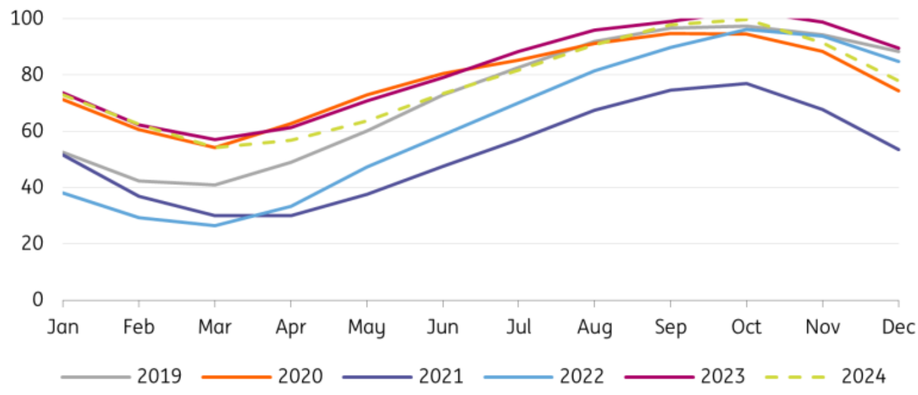
However, much will depend on how gas demand evolves through the year. In 2023, the lack of demand response to weaker prices surprised many in the market. Gas demand has remained well below the 5-year average and, in fact, for large parts of 2023, it was also down YoY.

In 2023, European natural gas demand was down around 18% from the 2017-21 average and also 8% below 2022 levels. For 2024, we are assuming demand will remain around 15% below the 2017-21 average through until the end of March. From April onwards, we assume a recovery in gas demand, which will see demand around 10% below the 2017-21 average, which suggests demand should grow in the region of 7% YoY. Less volatility and weaker gas prices should see some industrial consumers becoming increasingly more comfortable. However, obviously, if demand continues to disappoint, it will leave the market even more comfortable, and the EU will likely hit full storage once again before the start of the 2024/25 heating season.

A key driver behind weak gas demand is the power sector. Not only has electricity generation been weaker, but spark spreads were negative for much of 2023, which weighed on power generation from gas. Stronger renewables generation and the return of French nuclear capacity have meant power generation from fossil fuels was unprofitable for large parts of last year. Looking at forward spark spreads for the remainder of 2024, they are in negative territory and that suggests that demand from the power sector could remain weak.

Industrial demand is also still weak. Although, we are starting to see some signs of recovery in this area. Since August 2023, monthly industrial gas demand in Germany has grown YoY, with the exception of September. EU chemicals output could also be showing some signs of recovery, with output in November growing by around 1% YoY. Although, production over the first eleven months of 2023 was still down 8.7% YoY. The uncertainty for the market is how much of this lost demand will make a comeback or whether we have seen permanent demand destruction in the industrial sector, either due to substitution, energy efficiency gains or the permanent shutting of production capacity in Europe.

EU natural gas storage to remain comfortable through 2024 (% full)



Source: GIE, ENTSOG, Eurostat, ING Research

EUA demand pressures

The pressure seen on EU allowances (EUAs) towards the end of last year has only continued into 2024, with the market briefly breaking below EUR60/t in January and trading to its lowest levels since March 2022. While the longer-term outlook for EUAs remains constructive as allowances in the market are reduced, short to medium-term dynamics are more bearish. The EU has seen reduced industrial activity, which means lower emissions and the need for installations to surrender fewer allowances. Emissions over the first half of this year totalled 1.76b tonnes CO_2eq, down 4.2% YoY.

If we look at the power sector, in addition to overall power generation having fallen last year, we have also seen changes in the power mix. Renewables output has been strong, and in France, nuclear power output has also recovered, therefore reducing the number of allowances needed. EU electricity generation has been in YoY decline from March 2022 through to September 2023. Generation from coal and natural gas has been under pressure throughout the year, and this is not expected to change anytime soon. Both forward spark and dark spreads are in negative territory through 2024, suggesting that power generation from natural gas and coal will remain under pressure, which means demand for EUAs is likely to remain subdued from the sector this year.

Supply dynamics have and will continue to play a role in pressuring EUAs. This is partly due to REPowerEU, which aims to end the EU's reliance on Russian fossil fuels by diversifying energy sources, energy savings, and accelerating the roll-out of renewables. Part of the REPowerEU plan is set to be funded by the Recovery and Resilience Facility (RRF) through the sale of ETS allowances. The Commission's aim is to raise EUR20 billion from allowance sales. 40% of these funds are set to be met by bringing forward the auction of allowances scheduled to be auctioned between 2027-2030. These will now be brought forward to before 31 August 2026. Meanwhile, the remaining 60% will be met by sales of allowances from the Innovation Fund. Regulation from the Commission suggests this will be reached by the auctioning of around 267m allowances, although obviously, this will depend on where prices are trading.

While the outlook for 2024 is less supportive than originally anticipated, the longer-term picture remains bullish. Ambitious targets under Fit for 55 mean a more aggressive reduction factor will be used for allowances moving forward. A reduction factor of 4.3% per year will be used between 2024 and 2027 and 4.4% between 2028 and 2030. This compares to a previous linear reduction factor of 2.2%. In doing so, the Commission hopes to see emissions under the ETS fall 62% from 2005 levels by 2030 compared to a 43% reduction target previously. This is also slightly more aggressive than the proposed 61% reduction.

ING forecasts

	1Q24	2Q24	3Q24	4Q24	FY24
ICE Brent (US$/bbl)	82	80	82	84	**82**
TTF (EUR/MWh)	29	25	25	35	**29**

Source: ING Research

Renewable power: Stubborn challenges need to be addressed for sustainable growth

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Renewable power is a key pillar to decarbonising the world economy. We expect decent renewable power capacity growth in Europe and the US in 2024 and beyond. However, it's not happening fast enough because of vulnerable supply chains, high financing costs, congested grids and slow permitting

Global renewable power deployment: fast but not fast enough

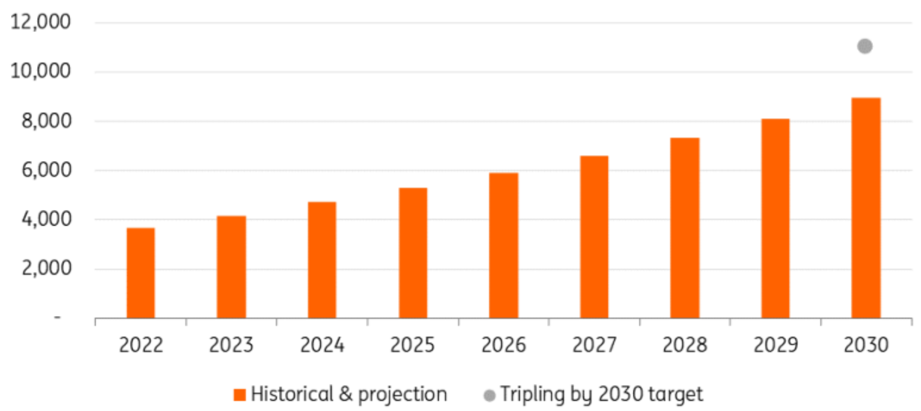
With the cost of renewable energy plummeting over the past two decades and renewable energy transitioning to a more mature market, global renewable power capacity additions have been reaching new records for 22 years in a row, according to the International Energy Agency (IEA). But the pressure is on to deploy renewable energy even faster. Different parts of the global economy, such as the transportation and industrial sectors, need renewable electricity to decarbonise their operations.

That is why, at last year's COP28, the United Nations' climate conference, governments agreed to triple global renewable power capacity from roughly 3,600 GW in 2022 to over 11,000 GW in 2030. Doing so can help the world reduce a third of the emissions needed to keep global warming within 1.5 degrees Celsius of increase compared to pre-industrial levels.

The IEA estimates that the world is likely to have over 4,700 GW of renewable capacity by the end of 2024, up from just over 4,100 GW in 2023. Under the currently projected policy and market conditions, global renewable capacity will have increased by 2.5 times by 2030.

Efforts fall short of what is needed to triple global renewable power capacity by 2030

Global cumulative renewable power capacity under current policies and economic conditions, in GW



Source: International Energy Agency, ING Research

This projection shows that while tripling renewable power capacity by 2030 is not completely out of reach, current policies and market conditions are not going to get us there. And when breaking down the data, one can also see that much of the growth will come from China thanks to its supply chain domination, substantially higher investment, and lower financing costs. In this article, however, we focus on two other major economies—Europe and the US—analysing the outlook for the renewables market and what is needed to roll out renewable development faster.

Europe and US: a better outlook for solar than wind

We expect a decent renewable power growth rate in the US in 2024. Specifically, the US Energy Information Administration (EIA) expects solar to be the main driver of growth in power generation this year, with its contribution to the power mix rising from 4% in 2023 to 6% in 2024. This contrasts with coal-fired power generation in America, which is forecast to drop by 9% this year because of comparatively higher costs and scheduled coal-fired power plant retirement plans. Wind power, on the other hand, has been more subject to challenges such as higher financing costs and supply chain disruptions and, therefore, will see a short-to-medium cool-down period.

Putting it together, solar and wind power in the US is expected to account for 17% of US electricity generation in 2024, up from 15% in 2023, which indicates a continuously growing renewable power market, albeit at a rather moderate rate. In the medium term, between 2023 and 2028, the US will likely add 340 GW of new renewable capacity, with solar being the main source of growth.

Europe, with a more comprehensive policy framework and a stronger need to transition away structurally from being dependent on Russian natural gas, is further along in solar and wind power deployment. According to Eurostat, in 2022, the EU already generated 15% of its electricity from wind power and 7% from solar power, together accounting for 22% of the generation mix. Solar generation grew the most between 2008 and 2022 and will remain the strongest driver for the 532 GW of anticipated renewable capacity additions between 2023 and 2028. Wind power is still expected to grow in the next few years, but the outlook for growth rates has weakened. To a lesser extent, wind power in Europe is also experiencing concerns over project financial performances and permitting complexities.

Persistent challenges, slow progress

The above-mentioned conditions and projections indicate that Europe and the US are set to fall short of the COP28 goal of tripling renewable power capacity by 2030, but not by much. So the two economies can still turn things around. Below, we detail the challenges facing the renewable power sector in Europe and the US, as well as the advancing, albeit slow, efforts to address them.

Elevated interest rates

Despite falling prices of wind and solar technologies, developers in advanced economies such as Europe and the US have been experiencing higher project development costs in elevated interest rate environments. Relatively more capital-intensive projects, such as wind, have been taking a bigger hit. Moreover, higher interest rates, coupled with inflation and supply chain woes, also mean that projects whose purchasing (customer-end) contracts were structured and signed based on lower interest rates face the challenge of not being able to bring enough revenue. This has indeed led some developers to delay or cancel projects in the hope of renegotiating contract prices. In the US, for instance, more than 10 GW of planned offshore wind capacity has been impacted, risking delays or cancellations, with interest rate-related costs being a major contributor.

Under such circumstances, policy support has become crucial to keep the renewable deployment momentum the US and Europe have experienced so far. And we do have enough reasons to believe that with Europe's RePowerEU policy (combined with other policies in the energy transition and climate space), as well as the Inflation Reduction Act (IRA) and Infrastructure Investment and Jobs Act (IIJA), the two regions should still expect continuous growth in the long term.

Congested grids and slow permitting processes

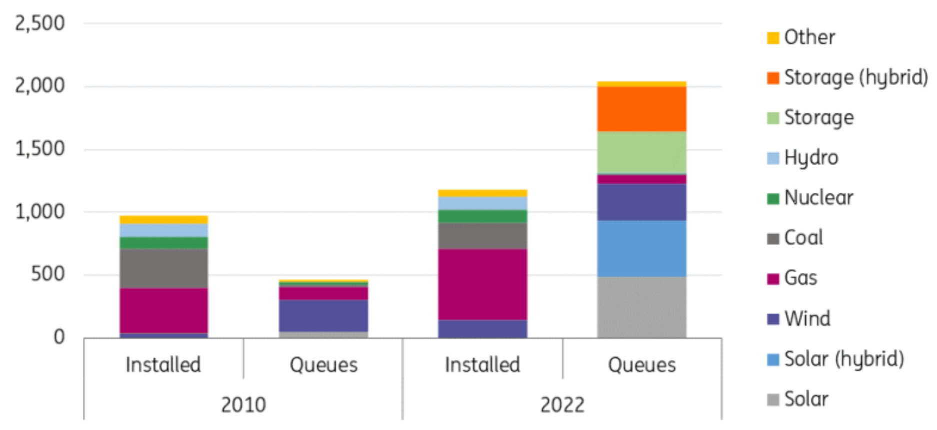
Another challenge facing both the European and US renewable power markets is grid congestion and permitting challenges.

In Europe, renewable developers in many countries have expressed challenges and, hence, negative impacts on project advancement because of complex and lengthy permitting processes. In some countries, such as Greece and Hungary, governments have stopped accepting applications for large-scale power projects. Efforts to change such situations are nevertheless underway. The EU has set a limit of two years allowed for permitting processes. Germany has simplified grid connection requirements for residential systems; the Netherlands is also working on accelerating the permitting procedures for renewable projects.

In 2022, more than 2 Terawatts (TW) of US power capacity were waiting to get online, the vast majority of which were solar, wind, and storage projects. The reasons for such congestions, as we have analysed before, include lengthy permitting processes and a lack of experienced government staff to review renewable projects. Remarkably, the 2 TW waiting capacity is higher than the total power capacity of nearly 1.3 TW in the US in 2022. That is to say, if all of the awaiting capacity were to get online today, the US would have more than doubled its power capacity almost exclusively with renewable energy. Recognising the problems, the Biden administration is working to speed up the permitting processes through proposed Federal Energy Regulatory Commission reforms. However, the progress is expected to be slow, given the amount of effort needed to bring visible changes to the current power system.

Renewable power capacity waiting to be connected to the grid has built up in the US over years

Capacity in GW



Source: Lawrence Berkeley National Laboratory, ING Research

For both the US and Europe, there is an urgent need to expand grid transmission capacity to accommodate more planned projects. The IIJA, for example, is allocating funding to build more high-speed transmission lines. Similar efforts are happening in Europe, though in both regions, it will take a while before developers start to see meaningful changes.

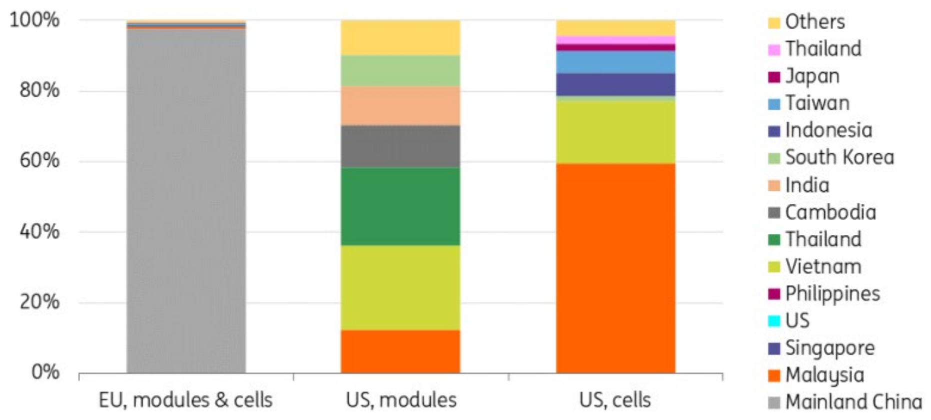
And in both economies, developers are increasingly interested in building up battery storage capacity along their renewable projects. In the US, nearly half of the proposed solar capacity and 8% of the proposed wind capacity in the queue are hybrid plants with storage capacity (although the IRA tax credits favouring standalone battery projects could alter this trend). In Europe, there have been government-led auctions of renewable-storage colocation projects (e.g. in Germany) and the rise of hybrid purchase power agreements (which allow a more flexible contract structure for renewable plus storage projects), though the designs of these mechanisms still need improvement.

Supply chain vulnerabilities

China controls the majority of raw materials and manufacturing capacity needed to build renewable equipment. The EU and the US largely depend on imports of renewable power equipment—particularly in the solar industry. In 2022, the US produced 5 GW of solar PV modules while importing 29 GW of solar PV models. Europe added 41.4 GW of solar capacity in 2022, while only 1.7 GW of wafers, 1.4 GW of cells, and 9.2 GW of modules were manufactured domestically.

In the first half of 2023, 98% of Europe's imports of solar PV modules and cells came from China, making Europe extremely dependent on only one country for its solar power raw materials. Although the US barely imports solar equipment from China because of trade restrictions, most of its imports come from Southeast Asian countries, which could likely be materials being rerouted from China.

EU and US are subject to supply chain vulnerabilities



Source: Bloomberg New Energy Finance, ING Research

Under such a context, securing supply chains will be a major theme for the renewables industry this decade and beyond. Both Europe and the US are working to enhance supply chain independence. The EU has vowed to become at least 40% independent in net-zero technology manufacturing capacity, while the US has included a series of domestic clean energy supply chain buildup policies in the landmark IRA.

Both regions are expected to develop solid clean-energy supply chains eventually, but it will take a long time and be costly. Before then, project developers around the world can expect additional protective policy measures from the US and the EU to protect their developing supply chains, including carbon border adjustment mechanisms, trade restrictions, import tariffs, etc. From China's side, it is unclear what the policy response will be, and there is a risk that the country might impose countermeasures, further complicating the geopolitics of the global renewables supply chain. These measures may not be beneficial for developers and raw material manufacturers from a global trade perspective, but it is something they will increasingly need to consider and manage.

We need more renewable power than ever

As various sectors accelerate toward electrification, the world needs more renewable power than ever. Significant drops in project costs and scale-ups in installed capacity in the past two decades are evidence that wind and solar power has entered a mature stage of development. However, such progress should not disguise the persistent challenges facing renewables. Faster adoption of renewable power needs comprehensive reforms in power system design, permitting, and labour education, as well as constant policy adjustments, to reflect the current macroeconomic conditions.

A return to reality in the path towards scaling up hydrogen

We expect the hydrogen market to grow in 2024, but less so than many have hoped for. The year ahead is also set to deliver policies for future growth. The actual number and size of new projects are less important; attention should now shift to turning them into success stories so that confidence in hydrogen is able to flourish

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Hydrogen provides a way to transition away from fossil fuels

Efforts to decarbonise the global economy are starting to reach a turning point as the COP28 climate conference reached agreements to transition away from fossil fuels. But the potential for renewables is limited in energy-intensive sectors, as electrons often cannot substitute the very high temperature heat. Nor are they a substitute for hydrocarbon molecules from fossil fuels that are needed to make products like steel, plastics, pharmaceuticals and fuels for aviation, shipping and trucking.

Carbon capture and storage (CCS) could reduce CO_2 emissions from these fossil-based activities to some extent but does little to 'transition away from fossil fuels'. Some fear that CCS might even prevent or delay this transition.

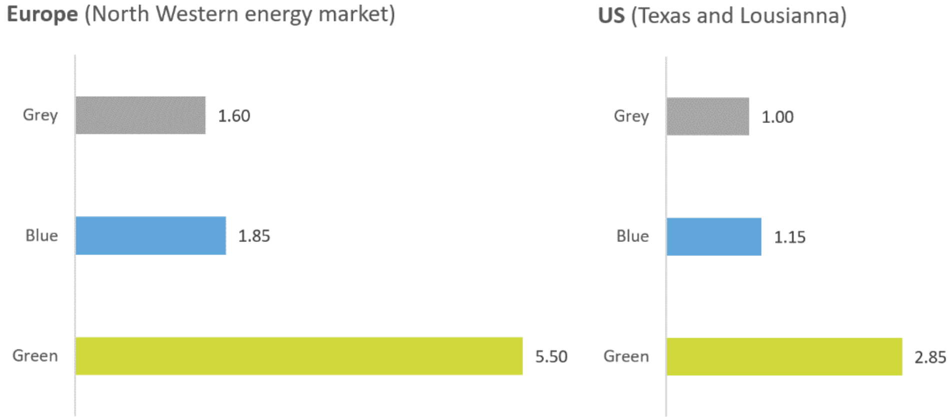
Hydrogen does, on the other hand, hold that promise as it is a substitute for fossil fuels – especially green hydrogen. It can generate high temperature heat and, by reacting with a carbon source like CO_2, it can create the feedstock needed to make steel and plastics. So here, we'll share our thinking on what will happen with hydrogen in 2024.

2023 failed to bring rapid and large cost declines

The year 2023 was somewhat disappointing. Project developers delayed investments in earlier announced pilot projects, especially for green hydrogen. It took politicians more time to work out the complex details of policies to build and scale-up a hydrogen economy. Europe and Asia still face high energy prices, making the energy-intensive hydrogen production and transportation process a costly business. Finally, new expensive and unproven electrolysers don't get a lot cheaper in just one year, especially when pilot projects are postponed.

Green hydrogen is still very expensive, especially in Europe where energy prices are high

Indicative unsubsidised hydrogen production costs in euros per kg



Grey and blue hydrogen costs are based on a gas price of €29/MWh in Europe and 3.5$/MMbtu in the US (€11/MWh). For blue hydrogen we assume a CCS capture rate of 85%. Green hydrogen is produced with a Western made alkaline electrolyser that costs around 1,000€/kW and runs with an efficiency of 70% and capacity rate of 70%. Furthermore, we assume a power price of €90/MWh for Europe and $40/MWh for the US (€36/MWh). We have converted all dollar-prices using an exchange rate of 1$=€0.91. Our results represent on-site production costs and don't cover hydrogen transportation or storage costs, which can be considerable if the hydrogen is used far from the production location and needs to be temporarily stored.
Source: ING Research

The prices of green hydrogen still put tears in taxpayers' eyes, in particular in Europe. Even with proposed subsidies in the range of €3/kg, it fails to be cost competitive with grey or blue hydrogen in many cases.

Higher interest rates have increased rather than decreased electrolyser costs in 2023. The anticipated learning curve for electrolyser costs has not materialised as expected due to fewer projects that reached final investment decisions in 2023. And while wholesale power prices came down last year, grid tariffs have increased considerably in many countries. Finally, strong cost declines for hydrogen are anticipated once there is a large global hydrogen market in which hydrogen users benefit from low-cost production regions. Currently the market is still very local, especially for green hydrogen, and it will take years to develop import and export hubs across the globe.

2024 will bring more realism to the hydrogen buzz

And optimism simply might have been too high in this early stage of the hydrogen economy, a trend that is common for new technologies. It took three to four decades to make renewable power cost competitive with power from coal or gas fired power plants. The solar and wind industry went through major boom and bust cycles during that process. The challenge for hydrogen is to reach this stage of market maturity twice as fast and without major market setbacks. We expect a lot more realism about the scale of such a challenge in 2024.

Hydrogen will show its true colours – and emissions – in 2024

We've been stressing that green hydrogen does not by definition lead to lower CO_2 emissions compared to using fossil fuels like gas. The CO_2 intensity of the power grid determines whether green hydrogen is good or bad for the climate. This is very relevant as power systems in many countries still depend to a large degree on fossil fuels.

As a result, politicians have expended a lot of effort on complex regulation to define the emission performance of hydrogen.

In **Europe** for example, the Renewable Energy Directive now includes rules for green hydrogen production with renewables:

- **Geographical correlation:** the solar panels or wind turbines that feed the electrolyser must be close by – that is, in the same bidding zone. That is likely to limit the use of

Power Price Agreements (PPAs) that span multiple bidding zones or even countries, which is currently common practice (for example, using green hydropower from Norway in the Netherlands through a PPA).

- **Temporal correlation:** hydrogen can only be called green if its production coincides with the production of renewable power from solar panels and wind turbines (monthly correlation until 2027 and hourly correlation afterwards). This time matching requirement can lead to more interest in projects where electrolysers and solar panels or wind turbines are co-located. Or it could trigger interest in off-grid development.
- **Additionality:** after 2027, only newly added renewable capacity can support green hydrogen production as existing power from wind turbines or solar panels is already used for other activities, such as charging electric vehicles.

Developers are likely to comply with these guidelines if they want the highest possible subsidies for their project.

Apart from green hydrogen, progress in Europe is also being made on defining low carbon hydrogen from natural gas and CCS (blue hydrogen) or nuclear power (purple hydrogen). The 'Hydrogen and Decarbonised Gas Market Package' defines emission thresholds that include standards to deal with upstream methane leakage and downstream hydrogen leakage as well as accounting rules for indirect emissions (the nuclear power and energy use of CCS). This regulatory clarity could boost activity in blue and purple hydrogen in 2024 and the years beyond.

In the **United States**, the long-awaited guidance on the 45V hydrogen tax credits from the Inflation Reduction Act was issued in 2023, albeit in draft form which is likely to become final in 2024. The scheme puts less focus on the hydrogen colour code, but more on emission levels. The tax credits can be as high as $3 per kilogram of hydrogen if the production process results in life cycle greenhouse gas emissions of less than 0.45 kg of CO_2 per kg of hydrogen. And projects must meet similar guidelines on locality, time-matching and additionality as in Europe.

We expect more final investment decisions for green hydrogen projects in 2024 because of clearer guidance on the definition of green hydrogen and requirements for policy support. A lack of guidance left project developers in the dark in 2023, which was one of the reasons that projects were delayed.

Should the focus be on hydrogen's emissions or building an electrolyser industry?

Industry and academics are still split over the need for strict definitions of green hydrogen production at this early stage of the market. Politicians clearly adopted a strict approach in order to ensure that every electrolyser has a positive climate impact. Some have advocated for a softer approach, fearing that strict rules are a barrier rather than an enabler of a green hydrogen market. They argue that most power markets will be almost carbon neutral from 2030 onwards, so why bother about the emissions of small pilot projects in the meantime?

In their view, the main purpose of current pilot projects is to develop and produce electrolysers, not so much to produce low-carbon hydrogen. The main goal, for now, is to build an electrolyser industry that can produce large-scale and cost-competitive electrolysers from 2030 onwards. That's when many power grids almost entirely run on low-carbon sources, and electrolysers cannot produce anything other than very low-carbon hydrogen. It is also the time that power systems are in dire need of large-scale electrolysers to absorb the vast oversupply of renewable power. Without electrolysers, wind turbines and solar panels should simply be curtailed, which is a shame and economic loss.

So, proponents of this view put more emphasis on the need for long-term industry support to build a green hydrogen economy rather than making sure that every pilot project results in lower carbon emissions compared to the use of fossil fuels.

Hydrogen won't surprise in 2024 unless demand kicks off

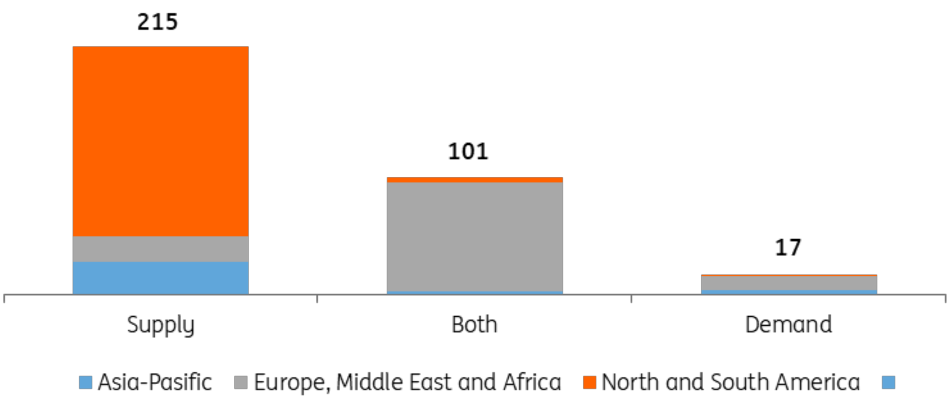
In our view, the industry is currently too focused on the supply side. Yes, hydrogen producers need subsidies to produce low carbon hydrogen, otherwise they continue to only produce grey hydrogen. And yes, hydrogen infrastructure is needed to build the hydrogen economy and bring hydrogen to locations where it can be used. But will it be used?

That will only happen if clean hydrogen solutions are cost competitive with fossil-based production methods. Unfortunately, that's far from reality yet. According to our calculations, switching from gas or oil to green hydrogen could increase the cost of plastic production by as much as 50% in Europe. Steel from green hydrogen could be twice as expensive compared to coal-based steel. And in shipping and aviation, cleaner hydrogen-based fuels can be up to ten times more expensive compared to regular fossil-based fuels.

Unfortunately, demand-side incentives have lagged far behind support for hydrogen production. Developers struggle to secure offtake agreements which then adds risk to the project, causing project sponsors to postpone the final investment decision.

Building a robust hydrogen market is all about balancing supply and demand, but support on the demand side is lacking

Global subsidies available for clean hydrogen in billion dollars



Note: 'Supply' funds support equipment manufacturing and H2 production. 'Demand' funds support end-use technologies and H2 use. 'Both' refers to programs that can fund supply and demand, and H2 transport and storage. Data as of 20 December 2023.
Source: BloombergNEF

However, this could all change in 2024.

In the US, Colorado and Illinois have introduced a subsidy of about $1 per kg for users of clean hydrogen, which is particularly aimed at stimulating hydrogen demand in hard-to-abate sectors like manufacturing. Pennsylvania has released a tax credit of $0.81 per kg of clean hydrogen purchased from a regional production hub.

And in Europe, the EU's Fit for 55 strategy and EU Emissions Trading System carbon trading scheme are starting to drive clean hydrogen demand in the coming years. Users of grey hydrogen must replace 42% of their hydrogen volume with green hydrogen. Under the ReFuelEU Aviation initiative, 1.2% of fuels supplied to aircrafts at EU airports must be hydrogen-based by 2030. And the FuelEU maritime initiative requires shipping companies to reduce emissions by 2% by 2025 and to pay a carbon price under the EU ETS scheme by 2026, which already increases demand for hydrogen-based fuels like ammonia and methanol.

Shipping and aviation companies operate globally and can tap into the lowest-cost hydrogen markets. Air France, KLM and Delta Air Lines signed a seven-year sustainable aviation fuel offtake agreement with US-based synthetic fuel producer DGFuels, made from over 800 megawatts of electrolysers, according to Bloomberg New Energy Finance. Maersk has signed the largest green shipping fuel offtake contract so far through a binding offtake agreement for methanol with Chinese renewable energy developer Goldwind.

But a lack of transparent pricing currently is another barrier for demand to kick off. Hydrogen offtake contracts are often bilateral and are undisclosed to other players. The market can benefit from initiatives to increase market transparency, for example by providing demand, supply and pricing statistics. The EEX Hydrogen Index in Germany is a good start, though development is still at an early stage. We expect and hope to see more progress on the demand side in 2024. The hydrogen economy simply won't take off without it. And increasing demand will feed into the supply side again, as more hydrogen storage facilities need to be built and exploited.

Key developments to watch in 2024

Overall, we expect more activity in the hydrogen market in 2024. At this early stage of the market, the exact number of projects or capacity added is less relevant. 2024 will be about laying the foundations for future growth and realising the first success stories that trigger confidence. These are the key developments the industry should be closely monitoring this year.

Key developments to watch in 2024

Developments that can spur (+) or delay (-) progress in the hydrogen market

Event	Effect
Elections 2024 is election year in many countries, including ones that drive the hydrogen market such as the US and EU. Green victories could spur development in the coming years (+), populism could mean a setback (-).	+ or -
Transition plans of energy intensive companies Sustainability investments by carbon intensive manufacturers: will they go for incremental change by first capturing emissions from current processes through CCS (-), or adopt more radical change in which hydrogen has a larger role to play in the medium term (+)?	+ or -
Electrolyser technology Some electrolyser projects faced technical issues in 2023. For example, Sinopec's 260 MW Kuqa project, which is the world largest green hydrogen system in China, is operating only 16 of its 52 five megawatt stacks. Multiple Western brands also faced technical issues. Continued problems could alarm potential investors in green hydrogen (-), whereas success stories could trigger appetite (+).	+ or -
Hydrogen auctions 2024 will have multiple hydrogen auctions, where project developers can bid for policy support. Revealed bidding prices will be a sign where the market is heading in terms of hydrogen costs. Will policy support be generous enough to exhaust available budgets (+) or does the market need more generous support (-)? These auctions will reveal the willingness-to-pay by both hydrogen offtakers, project sponsors and developers. Strong competition might be viewed as a good sign in the short term but could backfire in the long run if these projects turn out to be loss making. It is important to get the first projects right to build confidence.	+ or -
Policy support for hydrogen demand Increased policy support to stimulate hydrogen use for example in the production of steel, plastics, fertilisers and synthetic fuels. An uptake in large, long-term hydrogen offtake agreements will be a sign of progress.	+
Hydrogen supply chain Will all the parts of the full hydrogen supply chain (renewables, production, infrastructure, transport, storage and use) develop at the same pace? (+) Or will some parts lag and hold up the full market development? (-) Success stories in the hydrogen hubs where all parties jump in enthusiastically and work together and successfully complete project will build confidence.	+ or -
Electrolyser trade Electrolyser shipments out of China are a sign to whether other core markets can build their own electrolyser industry. Stagnant or reduced shipments could be a sign of progress as well as increased green industry support for electrolyser manufacturers in Europa and the US.	+ or -

Source: ING Research

Continued growth in CCS, but market struggles to kick off

CCS is a key enabling technology for the transition towards a net zero economy, and we're expecting its growth to continue building momentum in 2024. At the same time, unrealistically high hopes of a fast kick-off should start to cool down, and upcoming elections in key markets like the US and EU will only add to existing uncertainty

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Renewables are not the only answer

Efforts to decarbonise the global economy are starting to reach a turning point as the COP28 climate conference reached agreements to 'transition away from fossil fuels' and to triple investment in renewables.

But renewables are not the only answer to a net zero economy. Carbon capture and storage (CCS) helps to prevent CO_2 from entering the atmosphere and contribute to global warming. Here's what we're expecting to happen with CCS in 2024.

Growth isn't proving as fast as hoped for – or as needed

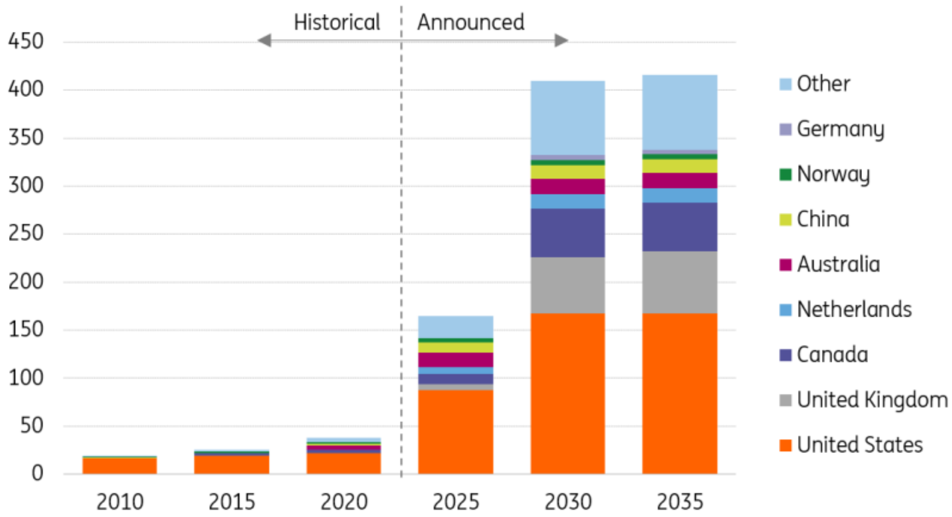
CCS technologies will continue to gain momentum in 2024. More companies in hard-to-abate sectors are committed to decarbonisation and are aware of the fact that CCS currently is a cost-effective technology for reducing emissions, for example in steel or plastics production. And governments increasingly support CCS.

Bloomberg New Energy Finance tracks CCS projects globally and notices an eightfold increase in CCS capacity towards 2030 based on current project announcements. Operational capacity could grow globally from around 50 megatons of CO_2 captured per annum (Mtpa) to 165 by 2025, and just over 400 by 2030 – provided that all announced projects follow through.

And that's the pitfall of forecasting capacity growth in this early stage CCS market. Not every announcement has the same status. Many announcements are about 'drawing board projects', few are about 'FID-projects' for which the final investment decision has been made and where construction is already underway, or will start soon.

CCS could grow eightfold towards 2030 if market announcement follow through

Global CCS capacity based in mega tons of CO_2 based on project announcements



Source: Bloomberg New Energy Finance

Given the pitfalls of early-stage CCS market forecasting, it doesn't make sense to forecast capacity numbers on a yearly basis. Projects take years to develop and their planning often moves back and forth. Therefore, we prefer to focus on the major market developments for 2024. This is what we see happening in the CCS market.

Most action happens in North America and Europe, but regions take different approaches

Countries have very different policy support schemes for CCS. The US provides tax credits, while CCS in Europe benefits from a combination of carbon pricing and direct subsidies. But things can differ greatly even between European countries. In the Netherlands, for example, the project owners take most of the risk with the government providing incentives. The UK, on the other hand, treats CCS projects more as infrastructure projects, with the government bearing most of the risk while offering a regulated return to project owners.

The introduction of the Inflation Reduction Act (IRA) in August 2022 caused a lot of excitement for CCS in the US. Now, almost one and a half years later, optimism has cooled as most of the nitty gritty details still need to be worked out by understaffed government bodies. As a result, application processes are long and cumbersome, and that makes project owners wary about making final investment decisions.

Furthermore, the IRA is not very popular among Republicans, even in red states like Texas that benefit most from it.. Tangible success in terms of smoother application processes and more FID-decisions would help prop up its popularity, but are unlikely to come soon – at least not before the start of this year's elections.

CCS costs differ significantly

Projects differ widely in the cost to capture, transport and store CO_2. This can range from €80 to €150 or more per ton of CO_2 depending on how easy it is to capture (pre-combustion versus end of pipe solutions), where it is stored (onshore versus offshore), how it is transported (pipelines or ships) and what storage facility is used (depleted gas field or aquifer).

Still, even the higher cost range for CCS is relatively cheap compared to other technologies designed to reduce CO_2 emissions, such as substituting fossil fuels with hydrogen or electricity. And it provides the opportunity to quickly reduce emissions from large emitters, which benefits the climate in the short term. Demand for CCS storage is therefore growing and outpacing storage supply at the moment. Storage capacity is likely to continue to be a scarce resource for large emitters in 2024 and beyond.

Hubs are reducing costs, but do not benefit every company equally

Most of the activity centres around CCS hubs are built to create economies of scale and reduce costs. CCS hubs are located around established industrial clusters. Prime examples are the Porthos and Aramis projects in the Netherlands, the East Coast Cluster and Acorn Cluster in the UK and the Alberta Carbon Trunkline in Canada. Oil companies in the US – primarily in Illinois and the Gulf Coast – are building offshore CO_2 storage hubs. Indonesia and Australia are doing similar things in their region. These hubs involve multiple stakeholders and industries, and sometimes several countries or states.

While these hubs are important enablers of sizeable emission reduction from industrial clusters, awareness is increasing that not every industry benefits from these clusters. Cement and waste incineration plants, for example, are often much more dispersed over the country and many cannot easily be connected to a CCS hub – but CCS is often the only technology available for reducing emissions from these activities. It takes more time to connect these remote sites through pipelines. Alternatively, more expensive CO_2 transport modes need to be developed (for example, by truck) for these sites to reduce emissions soon in order to reach national reduction targets.

Not a large banking market yet

Finance mostly comes from capital rich project sponsors like oil and gas majors (Chevron, ExxonMobil, Shell, PB, Equinor, TotalEnergies, AirLiquide), utilities (Gasunie, Ørsted), technology providers (Honeywell, GE) and off takers (ArcelorMittal, Nippon Steel, Baosteel, Ineos, BASF, Linde). They mostly finance CCS projects from their own balance sheets, so there is relatively little debt finance involved in this early stage of the market.

The banking industry is working to increase the bankability of CCS projects, so that these sponsors might be able to refinance in a couple of years and new projects can be financed with bank loans from the start. But a lot of things need to happen to improve the risk return profile of CCS projects..

In the Netherlands, for example, project sponsors remain responsible for carbon leakage to up to 20 years after the closing of the storage facility, which is a significant amount of time even for long term investors.

Second, knowledge on seismic, leakage, and regulatory and permitting risks need to increase in order to improve the public perception on CCS. More success stories need to enter the market to increase confidence and take away concerns from underperforming projects.

Finally, the whole CCS value chain needs to be in place – not only the capturing, transport and storage, but also the policy support and long-term CO_2 offtake agreements. And the merchant risk that kicks in the project when the policy support ends after, for example, 15 years, needs to be acceptable for debt financers.

The current CCS players, together with private equity companies, are also active in the M&A market to acquire CCS knowledge or projects, a trend we expect to continue in 2024.

Key developments to watch in 2024

Overall, we expect more activity in the CCS market in 2024, but the market continues to struggle to kick off and to show its full potential. But it has to if politicians and corporate leaders are serious about reaching the Paris Goals. Currently only 0.1% of global emissions are captured and stored, so they don't contribute to global warming. That number needs to increase to about 15% by 2050, according to respected scenarios for a net zero economy by both the International Energy Agency and Bloomberg New Energy

Finance. To put it more vividly, the European Union alone will need to capture emissions equivalent to those of Poland and Denmark combined to reach its ambitious 2050 climate targets.

And in the second half of this century, we need a lot of CCS globally to create negative emissions in order to undo the overshoot of global warming that is likely to happen. So, in the long run, the future for CCS could be bright. In the meantime, this is what we'll be watching in 2024.

Key developments to watch in 2024

Developments that can spur (+) or delay (-) progress in the CCS market

Event	Effect
Elections 2024 is election year in many countries, including ones that drive the CCS market such as the US, EU and India. Green victories could spur development in the coming years (+), populism could mean a setback (-).	+ or -
Transition plans of energy intensive companies Most progress is on the CCS supply side while the future challenges are on the demand side: will large emitters show strong demand in CCS facilities? Will they go for incremental change by capturing emissions from current processes (+) or adopt more radical change in which CCS ultimately has a smaller role to play (-)? We'll closely monitor CCS appetite from manufacturers.	+ or -
Cost awareness of CO_2 reduction Increased cost awareness in the design of CO_2 reduction strategies by both corporate leaders and public policymakers favours low-cost-CCS over more expensive technologies such as hydrogen, electrification or recycling.	+
Carbon pricing More firm carbon pricing could spur CCS in the medium term.	+
Blue hydrogen An increased role of blue hydrogen over green hydrogen in building a hydrogen economy could spur blue hydrogen as it is made from natural gas while capturing and storing most of the CO_2-emissions.	+
Social acceptance Continued debate over the need for CCS, its 'greenness', and where to apply it and where not, could delay progress. So can not in my backyard protests, especially for on-land CO2-storage.	-
Fossil fuel subsidies A reduction or phase out of 'fossil fuel subsidies' could make fossil fuel use more expensive and push large emitters towards electrification and hydrogen strategies, thereby lowering CCS appetite.	-
Policy support Delays in regulation and policy support for CCS projects.	-

Source: ING Research

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Power price normalisation and grids expansion in European utilities

The energy crisis is behind us, with the European Commission taking action to pret any major disruption over the coming years. European utilities will continue to grow in 2024 in terms of both cash flow generation and investment, but at a less hectic pace. The extremely elevated power prices seen in 2022 and 2023 are also entering into a normalisation phase

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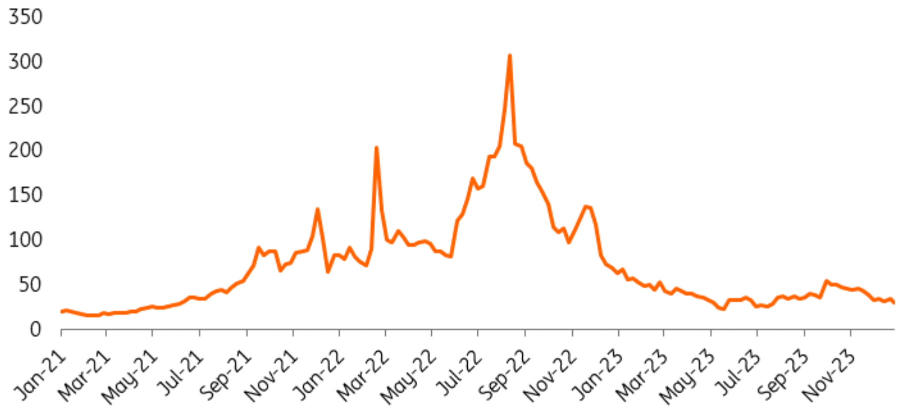
The elevated gas and power prices of 2021 and 2022 are behind us. In France, where half of the nuclear fleet was out of service for maintenance, the baseload 1y forward contract averaged €548/MWh in 2022 on the wholesale market. The lack of nuclear availability in the country added to the disruptions caused by the European economic recovery and the almost terminated natural gas procurement from Russia. With European utilities finding other gas providers, a phase of power prices normalisation started in 2023. Thanks to higher procurement from Norway and liquified natural gas resources from North America and Qatar, gas prices came back to lower and more stable levels. The natural gas TTF contract trades around €32/MWhc, far below the €300/MWh mark attained in mid-2022. For power prices, this means more acceptable tarrifs for residentials and corporates – although in 2023, they were still three times more expensive than in the 2016-2019 period.

The TTF 1 Month forward contract price (EUR/MWh) has eased



Source: Refinitiv, ING

Actions have been taken to avoid another energy crisis

The Dutch TTF natural gas contract (one month forward) traded around €32/MWh at the end of 2023. The price is far below what the markets experienced in 2021-2022, but still twice as much what consumers were paying in the 2016-2019 period.

At the height of the energy crisis, members of the European Union agreed on several measures to tackle excessive prices. The Market Correction Mechanism is one of the measures adopted. It is activated if the TTF price exceeds €180/MWh for three working days, and if the TTF price is €35/MWh higher than a reference price reflecting prices on international markets for the same three working days. Despite the fact that the mechanism has never been triggered since its implementation, the EU decided to extend the measure's expiration date to 31 January 2025 (from 1 February 2024 initially). The emergency measure to enhance European solidarity through better coordination of gas purchases is extended to 31 December 2024.

The reform of the energy market design for the long term

In November 2023, The European Council and Parliament reached a provisional agreement to reform the union's electricity market design (EMD). Overall, the reform aims at boosting fossil-free energy to cut CO_2 emissions as well as maintaining energy prices at affordable levels, especially in the event of a crisis. Several elements are tackled:

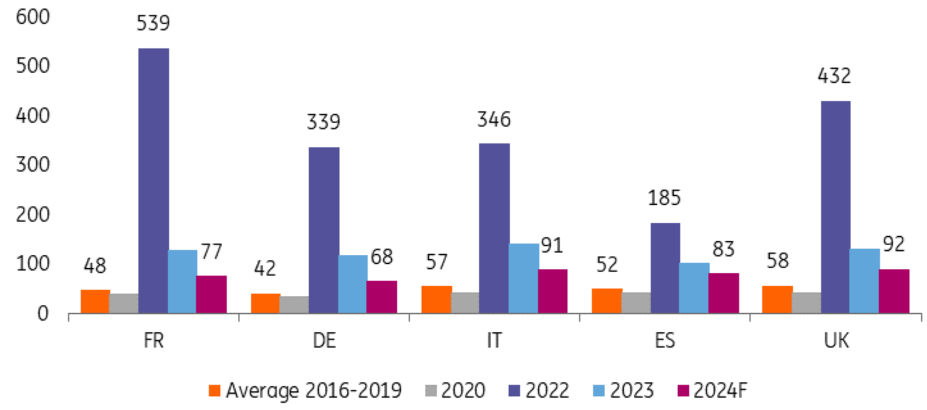
- **Protection of vulnerable customers:** measures to protect vulnerable customers from energy disconnections have to be reinforced across EU member states. Criteria for declaring a crisis were agreed upon and measures to support disadvantaged customers with reduced energy prices to support energy affordability.
- **Power Purchase Agreements (PPAs):** EU members are asked to encourage long-term contracts between power generators and clients.
- **Contracts for Difference:** two-way contracts for difference will apply to investments in wind energy, solar energy, geothermal energy, hydropower without reservoir and nuclear energy new facilities. EU member states will have the flexibility to redistribute the revenues made through the two-way contracts.
- **Capacity remuneration mechanisms:** when justified, exceptions can be introduced to the CO_2 emission limit for authorised capacity mechanisms. These mechanisms have to be become a more structural element within the electricity market.

Power prices will retrench further in 2024 but remain elevated

Power price expectations for 2024 shared by Standard & Poor's and some utilities point to wholesale power prices between 1.5-2 times higher than the period 2016-2019. Going back to power prices seen in the period 2016-2019 will probably not be possible in the short term unless a severe economic recession breaks out. Despite the Dutch TTF 1-month forward contract coming down to €32/MWh equivalent at the end of 2023, this price is still double compared to the pre-Covid pandemic period. In some parts of Europe, LNG shipments from the United States and Qatar have taken over the gas flows originally coming from Russia – but at a higher cost.

In the UK and Italy, power prices being 1.5 times higher than in the period 2016-2019 would result in an average price just above €90/MWh. In France, the electricity price in the period 2016-2019 averaged €48/MWh. Prices being 1.5 times higher in 2024 would result in an average power price of €77/MWh.

The average power wholesale 1Y forward contract (EUR/MWh) should decrease again in 2024



Source: Refinitiv, ING estimates

Elevated prices and a sluggish economy could continue to destroy electricity demand

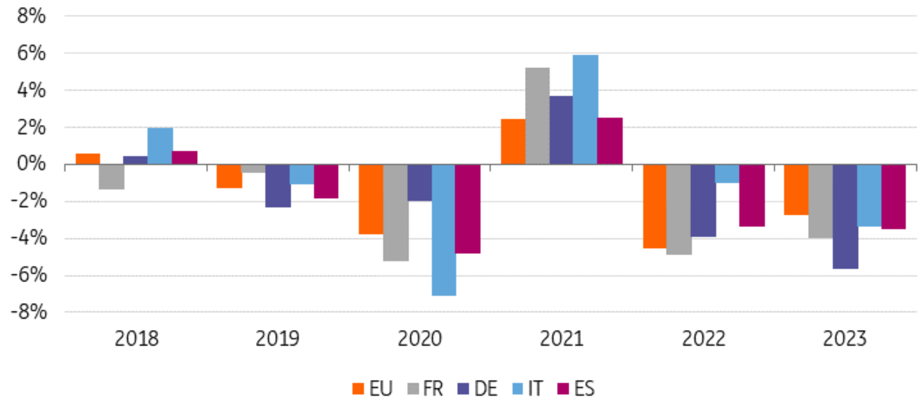
Electricity consumption experienced another decline in 2023. Globally, the European Union saw power demand falling by 2.8% in 2023 after a 4.5% fall in 2022. Germany saw the biggest power demand destruction last year with a 5.6% collapse.

Elevated power prices keep retail and corporate consumers aware of the cost of their energy bills. The economic recovery in 2021 after the pandemic shutdowns resulted in a strong power demand in countries such as Italy and France where restrictions were drastic. The increase in electricity prices in 2021/2022 led to retail consumers restricting their energy use. Across Europe, energy intensive industries limited their activities (and sometimes shut down factories) to avoid loss-making.

In their top three calls for the eurozone, our economists remain cautious on the outlook for spending, penciling in just 0.8% growth for 2024 (compared to a forecast of 1.6% by the European Central Bank and 1.2% by the European Commission). Consumption growth is likely to be limited by the turn in the labour market, with a gradual increase in unemployment limiting aggregate income growth. Even with a much more benign inflation backdrop, we expect eurozone consumption growth to remain subdued in 2024, keeping GDP growth below 0.5%.

A sluggish economy in the eurozone and power prices that retrench but remain elevated on a historical basis could see another year of power demand destruction. We would not be surprised to see another year of negative growth for power demand in 2024 – although we could expect the decrease to be less severe than in 2022 and 2023.

Power demand has been negative in the last five years (%YoY change)



Source: ENTSO-E, ING

European utilities' cash flow generation to progress again

In 2024, we expect that European utilities' cash flow generation will continue to progress. We estimate the sector's EBITDA to be on average around 7% stronger in 2024 compared to 2023. This increase comes from past investments bringing new projects online, higher remuneration on regulated grid activities and for some margins normalisation for their trading segment.

+7% average sector EBITDA growth in 2024

For the top 20 integrated utilities, we estimate their EBITDA to grow by around 5% on average. The growth corresponds to new renewable capacity coming online. Most integrated utilities also operate grids and will benefit from increased remuneration. Apart from a few utilities too dependent on Russian gas procurement, the sector has seen two years of extraordinary financial results derived from very high power prices. Utilities with a substantial portion of electricity produced by renewables benefitted from low cost generation which they could sell at elevated prices on the retail and wholesale markets.

In their 9M23 result publications, several European utilities informed analysts and investors of decreasing electricity prices. Consumers are locking in lower contract prices already. Power prices that are 1.5 times higher on average than during the stable period seen in 2016-2020 still mean comfortable cash flow generation in 2024 for the power generation business of integrated utilities – but also the start of a decline that will spread itself across several years due to the hedging strategies.

Regulated network activities to drive the growth for the sector

For the top 20 grid utilities, we forecast an average 9% EBITDA growth in 2024 vs. 2023. The elements that contribute to this strong increase are:

- Large investments that inflate utilities' regulated asset base and thus remuneration;
- Continued recouping of past costs;
- Inflation passthrough for utilities evolving in regulatory framework allowing inflation corrections;
- Revised WACC and/or remuneration formulas to account for higher cost of debt and/or higher costs in general.

+9% average EBITDA growth in 2024 for European gas and power network operators

Several regulators revised the remuneration of grid utilities in recent months. The low cost of debt during the period 2018-2021 – especially in Central and Northern Europe – negatively impacted regulated network utilities' cash flow generation. Remuneration either stagnated or even decreased, while an important financial effort was requested for the sector to develop and adapt its network assets to accommodate the transmission and distribution of renewable power and gas.

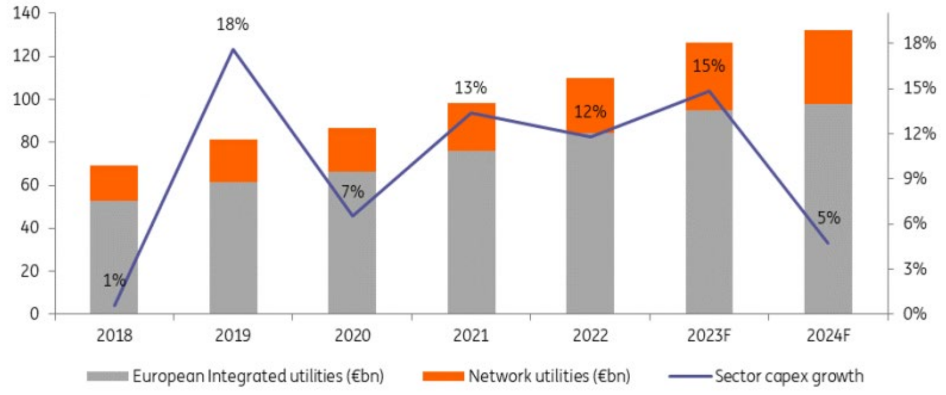
The hike in the post-Covid cost of materials and the energy crisis in 2021 and 2022 dramatically changed the operational cost conditions of European corporates, including network utilities. Added to this were rate increases impacting financial markets and the yield paid on new debt issuance. Some corrections were brought to the remuneration formulas (quite often based on a WACC methodology) and while 2023 already saw some recouping of costs occurred in the past, 2024 will see remunerations going up again in several European countries.

- **Belgium:** Still with a cost-plus model, the national electricity transport company Elia Belgium will benefit from strong tariff increases in the coming years. Over the period 2024-2027, the tariffs the utility can charge to its users will grow by 77% with an average return on equity set at 7.2% instead of the average 6% in the period 2020-2023.
- **Germany:** In June 2023, the German regulator Bundesnetzagentur (BNetzA) announced a regulatory return on equity (ROE) increase to 7.09% pre-tax (or 5.78% post-tax) for new onshore investments. The remuneration for grid assets built before 2024 will remain at 5.03%.
- **Italy:** in November 2023, the Italian regulator ARERA published the final determination for the new allowed WACC for electricity and gas networks for 2024. The revision of the risk-free rate, the country risk premium and the sovereign bond yields led to higher weighted average cost of capitals (WACCs) for most activities. On average, WACCs will increase by 80 basis points. For instance, regulated assets for power transmission activities will be remunerated at 5.8% instead of the 5% set for the period 2022/2023. Gas distribution activities will be remunerated at a 6.5% WACC, which replaces the 5.6% in the former regulatory period.
- **The Netherlands:** in its tariff methodology 2022-2026, the Dutch regulator (ACM) determined an average nominal WACC of 3% for the network utilities operating on the territory. The cost base is the year 2020. The initial methodology includes an average inflation of 1.7% per year and an average cost of debt around 0.5%. After court actions, the Dutch transmission and distribution utilities obtained a revision of their remuneration. In 2023, the WACC was brought up to 4% and will reach 4.5% in 2024. The cost base is now the year 2021, which offers a better picture of the operators' cost structure. The recouping of past costs will again boost the regulated utilities' cash flows in 2024, something much needed given the large investment plans that need to be executed. For consumers, the bill for network services averaged €380 in 2022. In 2023, the amount climbed to €513 (+35% vs. 2022) and is expected to be slightly above €600 in 2024 according to our calculations.

A milder investment increase in 2024

In 2024, the top 40 European utilities* will invest a total of €132bn in the maintenance and development of their grids, renewable base and conventional energy generation assets. According to the utilities' strategic plans and our estimates, this global amount compares to €126bn for the full year 2023, representing a 5% growth year-on-year.

Sector average capex growth (%)



Source: Company data, ING

+5% average investment growth for the sector in 2024

Looking back to the period 2018-2022, the sector's investment plans have grown by a staggering average of 11% per year going from c.€70bn in 2018 to €110bn in 2022.

The 5% increase that we forecast for 2024 is therefore less important than what we have seen in the last five years. We see a couple of reasons for that:

1) Investments reached exponential expansion in the period 2021-2023 and the growth is now slowly returning to a more average level (especially for integrated utilities).

2) With (renewable) projects more expensive, as seen with Orsted and Vattenfall, European utilities become more selective as they want to secure appropriate levels of return on investment.

Higher costs result in a more selective approach toward renewables

Just like many industries, soaring commodities and material costs have impacted the Utilities sector. Purchasing costs for renewable equipment, especially offshore wind farms, have made some utilities renouncing some of their projects.

Recently, the Danish utility Orsted announced depreciation of €2.1bn on its US offshore wind farm projects. Soaring costs, higher interest rates and uncertainty on related subsidies have had a dramatic impact on expected return on investment. Vattenfall, the Swedish incumbent, inaugurated its offshore windfarm on the Dutch coast but announced it was suspending the development of its 1.4GW Norfolk Boreas offshore wind farm programmed to power 1.5mn UK homes.

According to the Swedish utility, costs on the project have increased by 40%, negatively impacting the company's future earnings.

The Italian incumbent Enel presented its new strategic plan in December 2023, in which investments in renewables for the period 2024-2026 are revised downward, especially for onshore wind. With higher returns, Enel decided to allocate more capital expenditure in its regulated network activities.

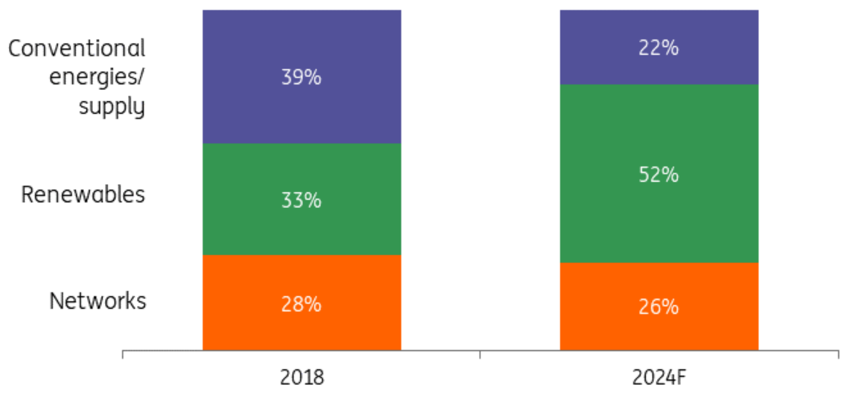
In September 2023, the UK failed attracting bids for its offshore wind power auctions. Offshore wind developers argued that the government's offer did not match the surging costs and higher funding expenses. The same reasons explain the poor auction results that Spain registered in December 2022. Only 50MW of wind projects were subscribed when the authorities planned to allocate 3.3GW of new onshore wind power and solar panels.

Several European utilities have a foothold in North America where they operate power plants (renewables and/or conventional energies) and sometimes transmission/distribution networks. The US has been amongst the favourite places for developing renewable activities thanks to attractive fiscal policies.

In the last few months, major European players such as Orsted, EDP and Enel have announced US disposals, mostly concerning wind projects and sometimes solar and geothermal. In its 2024 renewable energy industry outlook, Deloitte underlined the good performance of the solar industry which saw installed capacity growing by 36% in 2023. At the same time, additional capacity from wind projects came at 2.8GW, 57% down compared with 2022. The consultancy firm cites an average cost increase of 50% for wind projects between 2021 and 2023, which led to a diminishing pipeline. The difficulties in obtaining permissions and connections to the grids are other reasons for the disaffection for wind projects.

The shift of European integrated utilities' business model from conventional energy generation producers and suppliers (coal, natural gas and nuclear) towards renewables is reflected in past and future investments. In 2018, 33% of total investments were dedicated to renewables. We forecast renewables to represent 52% of total investment in 2024. With conventional power generation plants being shut down or disposed of, capital expenditure for this segment is on a significant decline from 39% in 2018 to 22% in 2024. Despite higher costs, European utilities remain committed to delvering on their carbon emission reduction targets.

European integrated utilities' investments per segment



Source: Company data, ING

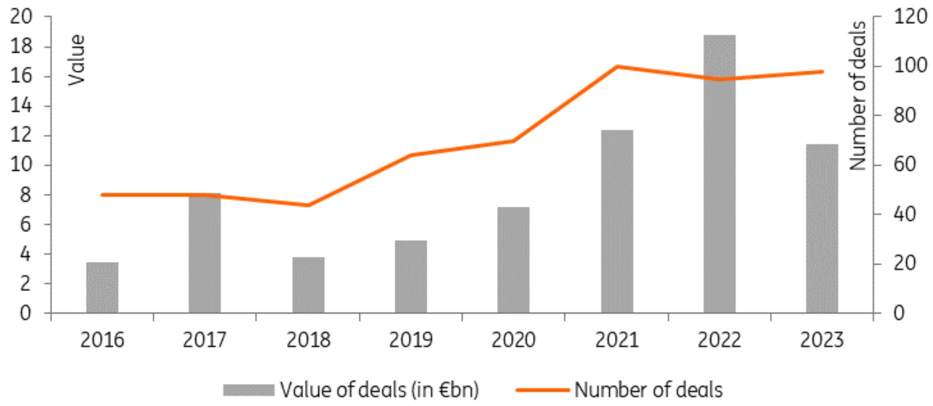
Developing renewables portfolios through acquisitions will progress again if funding costs abate

While the priority has shifted to selecting projects that will guarantee a decent return on investment, European utilities continue to be largely involved in the development and operating of renewable power plants. The reshuffling of portfolios through asset disposals or asset rotation to achieve higher returns on investments comes alongside new project developments as well as acquisitions. The difficulties in developing renewable projects are acknowledged by most utilities. Timeframes for obtaining the necessary permissions, the extensive administration tasks, higher material and staff costs and the delays in connecting the new power plants to the grids have been hurdles for the sector.

European utilities such as RWE, Engie and Elia have been active on the M&A market in 2023, with the acquisition of local players that offer a pipeline of projects already in place. The advantages of M&A activities allow utilities to avoid parts of the hurdles inherent to the several phases between the conception of a project and its operation.

The period between 2018-2022 saw a strong increase in merger and acquisition activities concerning "alternative energies". The figures for 2023 point to a weaker year and, although the number of deals were in line with those seen in 2022, the amount in EUR terms fell significantly to €11.4bn. As the next section explains, funding costs significantly increased for corporates, making it more difficult for M&A opportunities to materialise. We would expect M&A activities for the sector to grow again if funding costs lessen.

M&A volumes for alternative energies in North America and EMEA declined in 2023 on higher funding costs



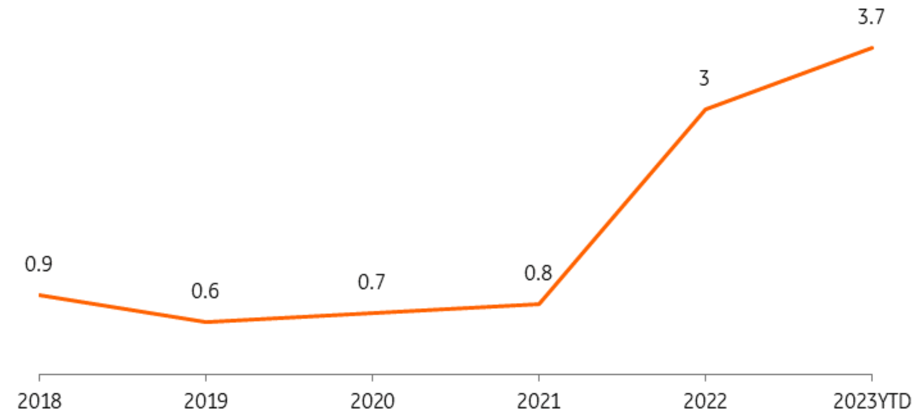
Source: Bloomberg BNEF, ING

Financing costs sharply increased

Due to its capital intensive nature, the European utility sector is a heavy user of bank loans and bonds. While parts of investment need to be financed by new financial instruments, utilities also face loans and bonds redemptions. On top of higher operating costs, the sector has to finance parts of its capital expenditure and refinance its debt at much higher interest rates than in the last five years.

Today, the sector pays an average of 3.7% in yield for a five-year senior bond. In 2022, this yield was 3% on average. In the period 2018-2021, utilities could issue five-year senior bonds with an average coupon of 0.8%. Our ING rates strategists believe that the European Central Bank will start cutting rates over the course of 2024 and that a "neutral" 2-2.5% rate by the end of 2025 could be achieved.

Average yield paid by utilities on new debt issued on the EUR bond market (%)

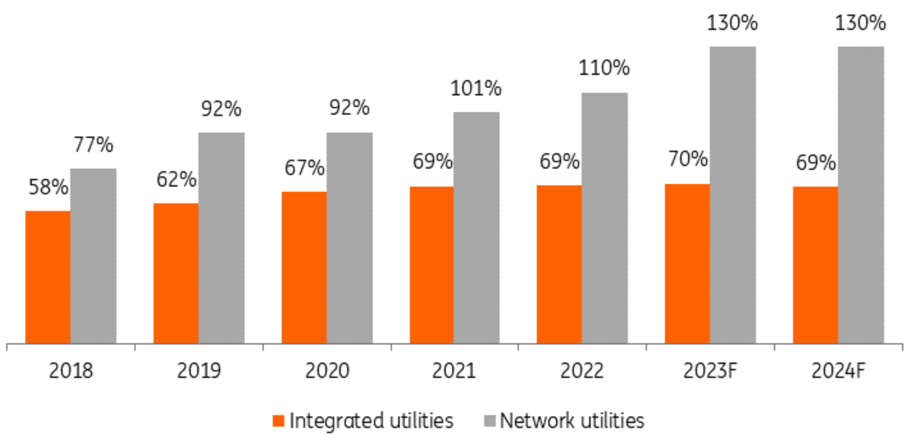


Source: ING

Financial leverage remains a concern

Parts of capital expenditure plans are financed by debt, especially for network utilities whose regulated cash flow generation does not provide them with the sufficient funds to finance investment plans. In 2023 and 2024, we deem network utilities' investment plans to surpass earnings before interest and depreciation (EBITDA) by 30%. For integrated utilities, earnings are sufficient to finance capital expenditure needs. However, EBITDA represents the revenues generated by the activities taking into consideration operating costs and operating taxes. The financial indicator does not take into consideration interest expenses on financial debt, and the remuneration of shareholders.

Capital expenditure to EBITDA ratio (%)



Source: Company data, ING

Due to the funding needs of European utilities (especially network utilities) we do not expect the sector to improve its financial leverage ratios. 2024 should see the beginning of a phase of normalisation for power and gas prices. Nevertheless, the geopolitical situation in the Middle East could bring volatality to the markets in case of escalation. The sector seems to be better prepared today in the case of an energy crisis.

*The top 40 European utilities: A2A, Acea, Alliander, Amprion, Centrica, EDF, EDP, Elia Belgium, Enagas, EnBW, Enel, Enexis, Engie, E.ON, Eurogrid, Fingrid, Fortum, Fluvius, Fluxys, Hera, Iberdrola, National Grid, Naturgy, Nederlandse Gasunie, Redeia, Redexis, REN, RTE, RWE, Snam, Statkraft, Stedin, Suez, TenneT, Terna, Orsted, Vattenfall, Veolia, Verbund, Viergas

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