GAS STORAGE IN THE ENERGY TRANSITION

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The main value of gas storage has traditionally focused on security of supply, ensuring people can continue heating their homes in the event of a cold spell or a sudden supply cut. That is due to change in the coming years as energy companies compete for new ‘flexibility’ services in a hybrid energy system combining gas and electricity.
Departing from its usual supply security role, gas storage is vying for a central position in Europe’s vision of a hybrid energy system combining renewable electricity and low-carbon gases like hydrogen. But getting there won’t be a smooth run and regulators are watching closely.

The main value of gas storage in Europe has traditionally focused on security of supply, ensuring people can continue heating their homes in the event of a cold spell or a sudden supply cut.

That is due to change in the coming years. Gas storage operators are increasingly positioning themselves on new markets – first as back-up for variable wind and solar power and, in the long run, as established providers of “flexibility” services in a future energy system where electricity and gas will be more closely integrated.

With 1,200 terawatt hours (TWh) of existing capacity in Europe, the potential of gas storage is indeed massive. But the road to such a hybrid energy system is paved with uncertainty. And, in the meantime, immediate challenges are becoming more pressing.

“The situation has dramatically changed over the past ten years. Gas is much cheaper now than a decade ago and that has considerably weakened the commercial value of storage,” says Ilaria Conti, head of gas programme at the Florence School of Regulation.

“Nowadays, with the declining price of gas, that value has fallen and storage sites have even become a financial burden in some cases, forcing some companies to close down unprofitable sites,” she told EURACTIV

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in an interview.

As such, falling gas prices are good news. It shows EU efforts to liberalise the gas market have actually borne fruit, bringing cheaper gas to consumers. Network connections have also improved significantly, meaning gas can now flow more rapidly to where it’s needed, making the system more resilient than in the past.

But for storage operators, lower gas prices has also brought new challenges.

From up to €10 or €12 a decade ago, the spread between summer and winter prices on the TTF gas hub in the Netherlands has now fallen to €2 on average. Meanwhile, the cost of gas storage has remained unchanged, hovering around €5 or €6 per Megawatt hour (MWh).

This means there are now fewer incentives to replenish storage sites in the summer when prices are low, Conti said. According to industry data, gas storage capacity dropped by 4% over the last two years, as more sites were forced to close down on the back of falling prices, said Gas Infrastructure Europe (GIE), a trade association.

GAS STORAGE “PARADOX”

This has direct implications for energy security. “The risk of demand load curtailment arises from as little as 10% reduction in gas storage” in a cold winter, GIE said in statement earlier this year.

Such supply security risks were illustrated in February last year when Britain and Ireland were hit by a cold wave dubbed ‘the Beast from the East’, which brought polar air from Siberia into Europe. The timing was particularly bad. The year before, British Gas owner Centrica announced the closure of the country’s largest gas storage facility, citing economic and safety reasons.

When Britain was hit by the cold spell, gas demand soared to multi-decade highs and energy operators had to resort to imports of Liquefied Natural Gas (LNG) coming from Qatar and – for the first time – the US. The UK’s coal power plants were also called to the rescue, running almost flat out during the cold snap in order to reduce the need to burn gas for electricity.

For Conti, the ‘Beast from the East’ was a perfect illustration of the “insurance value” that gas storage brings to the energy system. “Europe wouldn’t have been able to go through the cold spell without gas storage,” she says.

“This is the gas storage paradox: prices go up when there is a need to tap into the storage sites. But there are no incentives to replenish them when the prices are low.”

Few European countries are likely to experience the same problems as the UK. Gas storage facilities are still regarded as strategic assets, especially in places like Poland and Hungary, which are highly suspicious about over-reliance on Russian imports.

However, the immediate future looks uncertain because the market ignores the “insurance value” of gas storage. “It’s important that the market recognises this insurance value and remunerates it,” Conti insists. National regulators could help achieve that, she says, but they also “need political guidance at EU level to ensure consistency of the decisions taken with a long-term perspective”.

FUTURE VALUE

A long-term EU perspective is precisely what the gas industry misses most.

In November, the European Commission published a long-term strategy for energy and climate change, making the case that Europe should cut global warming emissions to net-zero by 2050 in order to meet its Paris Agreement objectives.

That target still needs to be endorsed by EU member states, which have conflicting views on the matter. But whatever target is eventually adopted for 2050, gas network operators are coming to terms with the fact that natural gas of fossil origin will have to be gradually eliminated from the EU’s energy mix.

Together with electricity grid operators, they have already started working on zero-emission scenarios for mid-century as a part of a joint network development plan. “And that automatically means there will be no fossil gas in the mix by then,” said Jan Ingwersen, general manager at the European Network of Transmission System Operators for Gas (ENTSOG), who spoke to EURACTIV in a recent interview.

For gas storage operators, linking up with the electricity system means a radical departure from their traditional business model. In fact, it opens an entirely new set of challenges and opportunities.

Currently, the interaction between gas and electricity is mostly a one-way street where gas turbines produce electricity, often as a back-up for variable wind and solar power. But more of the opposite is now beginning to happen, with power-to-gas facilities converting electricity into hydrogen which can then be stored in the existing gas network.

According to the European Commission, such power-to-gas installations could fill an essential role in the future energy system by enabling the storage of renewable electricity production coming from wind and solar power.

“What we see for the future is a combination of gas and electricity as energy carriers – so a hybrid system approach, which is also referred to as sector coupling,” Ingwersen said.

TOWARDS A HYBRID

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ENERGY SYSTEM

Such a hybrid energy system mixing gas and electricity is actually at the centre of the European Commission’s 2050 scenarios.

“Combining the electricity and gas infrastructure – for us in the Commission it’s clear that it’s the way to go,” said Klaus-Dieter Borchardt, deputy director general in the Commission’s energy department.

According to Borchardt, the benefits of doing this are clear. Using existing gas infrastructure rather than building new power lines brings obvious cost savings to the wider energy system, he told participants at a recent EURACTIV event. Moreover, an economy entirely reliant on electricity would require a fully digitalised infrastructure, which increases the threat of cyber-security, he pointed out.

“A hybrid system based on two pillars, in our view, is more resilient and would really add to security of supply,” Borchardt said, citing “the storage capacity” of the gas system as an example of the future value gas can provide in a low-carbon economy.

Even the electricity sector doesn’t dispute the value of gas storage in a hybrid energy system, because it reduces the need to build new power lines.

“We fully support the basic finding that there is a big storage potential in the gas system,” said Kristian Ruby of EU power sector association Eurelectric, who also spoke at the EURACTIV event.

“Much as we want, we can’t put up all the wind turbines that we would like because citizens don’t want them. Much as we want, we can’t put up all the transmission lines that we want, because citizens don’t want them,” Ruby told EURACTIV in a recent interview.

However, he also drew attention to electricity storage, which is expected to grow exponentially in the coming years as the cost of batteries continues to fall.

“Is the future all electric? No, we know that,” Ruby said. The real question, he added, is whether low-carbon gases like hydrogen can be produced in sufficient quantity to contribute to the decarbonisation of the energy system.

Moreover, reliable estimates are hard to come by. The European Commission’s Klaus-Dieter Borchardt said the jury was still out about how much cost savings gas infrastructure could actually bring in a hybrid energy system, pointing to wide divergences in the cost-benefit studies currently available. And while it was “common sense” to assume there will be cost savings, a conclusive estimate is not yet available, he said.
Boasting 1,200 terawatt hours (TWh) of existing capacity, gas storage sites can be a formidable asset for Europe in the transition to a low-carbon economy, providing much-needed flexibility to a future energy system where gas and electricity will be more closely integrated, says Ilaria Conti.

Ilaria Conti is head of gas programme at the Florence School of Regulation, European University Institute. She spoke to EURACTIV’s energy and environment editor, Frédéric Simon.

INTERVIEW HIGHLIGHTS:

- Gas storage remains a strategic issue for many countries, providing “insurance” in the event of a cold spell or a sudden supply cut
- But falling gas prices means there are fewer incentives to replenish stocks in the summer, which raises energy security issues
- In future, existing gas storage sites can easily be transformed to take low-carbon gases like hydrogen, at low cost
- Debate ongoing about whether power-to-gas installations should be considered a storage site or an energy generation facility.

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How has the gas storage market evolved over time? What were the big trends in the past 10-20 years on that market?

Like for transmission pipelines, gas storage activities used to be vertically integrated with gas supply and generation activities before the Third Energy Regulatory Package was adopted in 2009. And now the two activities are supposed to be separate – or “unbundled” in EU legal jargon.

Now, like for transmission activities, the level of separation may still vary. Some Storage System Operators (SSOs) may be privately owned while others may be publicly owned, in part or in full. Additionally, access to storage can be regulated or negotiated.

You say storage is “supposed” to be separate from gas generation activities. Do you mean the unbundling process is not fully completed?

Just like for transmission activities, there are different levels of unbundling depending on the countries. Overall, we can say the process has been completed but there are some countries where it has gone further than others.

Additionally, SSOs can be publicly or privately owned. In Italy, for example, the main operator Stogit is part of SNAM (the gas TSO) which is partly public, but there are also 100% privately owned operators, like Edison Stoccaggio or Italgas.

So ownership unbundling has brought new operators on the storage market, which used to be dominated by state-owned companies, right?

Yes, that’s exactly the same trend that we saw in the transmission and distribution segment. Currently, we estimate that the largest majority of operators are privately owned and only a few are publicly-owned.

That also means increased competition on the gas storage market, which must be a good thing, I suppose?

Certainly, this is one of the benefits of liberalisation. On the other hand, liberalisation in the gas storage market has a different significance because it is strongly linked with security of supply and geography.

Gas storage remains a strategic issue for many countries, which may impose obligations for strategic reserves in case of a supply cut. In Hungary for example, there is a specific operator in charge of strategic storage.

Storage capacity in Europe is estimated at 1,200 terawatt hours (TWh). That must provide a welcome assurance in relation to exporting countries like Russia, correct?

The situation has dramatically changed over the past ten years. Gas is much cheaper now than a decade ago and that has considerably weakened the commercial value of storage.

Having gas storage sites full and ready to use was considered a great value for companies and for the states where the storage sites are located. Nowadays, with the declining price of gas, that value has fallen and storage sites have even become a financial burden in some cases, forcing some companies to close down unprofitable sites.

Still, the big value of storage today is in security of supply in case of disruption. It’s true that having European storage sites full is a relief for EU member states because we know we would be ready for a gas crisis, even though this would be enough for a couple of weeks maximum. All the simulations in the stress tests point in that direction, assessing European self-sufficiency by under harsh conditions like a two-week cold spell in winter time, for example, even when storage sites are completely full.

In a way, liberalisation has worked because prices have gone down. But it also had the undesirable effect of depressing the storage market, which forced closures in some cases...

It’s true that storage sites are planning to close down because they have become too costly and financially unsustainable. But I wouldn’t say liberalisation has worked because prices went down. It worked because we have a much better functioning market with harmonised rules and referenced pricing.

Gas prices used to be linked to oil prices but nowadays the main references are the hub prices in the UK and the Netherlands, where price formation is much more transparent. And this is one of the biggest achievements of the liberalisation process.

Prices went down as a consequence of liberalisation but it’s not the only reason. First among those is the European Commission’s push to aim for an energy mix based on renewable electricity. This has dimmed the long-term future prospects for gas demand in Europe.

Reducing Europe’s reliance on imported gas is good news, even though it brings worries for gas industry operators...

It depends on the point of view. Cheap prices are always welcome by final consumers. But there are other actors in the gas value chain, like Storage System Operators.

In fact, we are in front of a total paradox here – the gas storage paradox. On the one hand, the value of storage was clearly demonstrated last year during the cold spell – the ‘Beast from the East’. It was a clear...
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demonstration that storage is still essential for security of supply in Europe.
But at the same time, that value of storage is not priced at the right level – there is currently a very low spread between summer and winter prices of storage. And therefore, there is no appropriate remuneration for operators to store gas when prices are low.
As an example, gas prices went through the roof after the cold spell but immediately dropped again afterwards. This is the gas storage paradox: prices go up when there is a need to tap into the storage sites. But there are no incentives to replenish them when the prices are low.

For gas storage, what’s the typical price fluctuation now between winter and summer? And how does it differ from ten years ago?

The summer and winter price spread at the TTF hub in the Netherlands used to go up to €10 or €12 in 2006-2007. Last year, it was around €2. And that’s too little incentive to invest in gas storage.

Looking ahead to 2050, the European Commission sees the future of gas as a complement to electricity. What will be the value of gas storage in such a hybrid energy system?

Traditional storage of natural gas will continue to play a role until 2030-35 and maybe a bit longer – mainly for supply security reasons, and also in a transition phase, as a backup to renewables.
So it’s important that the market recognises this insurance value and remunerates it. The ‘Beast from the East’ last year was a good example: Europe wouldn’t have been able to go through the cold spell without gas storage. So we should understand what the value is and properly remunerate it.

And that is something regulators can help achieve?

Yes, definitely – national regulators can help. But there needs to be political guidance at EU level to ensure consistency of the decisions taken with a long-term perspective.

Gas network operators say storage infrastructure will bring services to the future energy system – in terms of flexibility and in support of decarbonisation efforts. How can such “services” be rewarded in the future EU regulatory framework?

I would distinguish between the value that gas storage sites have at present – storing natural gas for supply security reasons – and the potential they will increasingly have in the future when it comes to storing other types of gas.

If you assume fossil fuels will be phased out by 2050, including natural gas, it’s important to remember that existing storage sites can be transformed to store other types of gas, at low cost. So in this sense, the potential they have is big. And this is particularly the case if the European Commission wants to promote investments in renewable gases and hydrogen.

You mentioned hydrogen. The European Commission says an energy system based on renewables will require a lot of green hydrogen and power-to-gas facilities. What are the key principles that policymakers should observe when regulating this sector?

There are two different dimensions. Natural gas is currently abundant whereas renewable gases – biogas, biomethane and hydrogen – are still in limited supply at the moment. So one of the first thing is to evaluate the real potential of these renewable and low-carbon gases.

One of the main features of the gas storage system today is that it is sizeable and can be tapped rapidly. But it’s not clear yet whether the future energy storage system will manage to keep this essential feature.

Then, future power-to-gas installations are still pilot projects. They will need to demonstrate how easily they can be activated for the needs of the energy system, which will become more volatile because of variations in renewable electricity coming from wind and solar.
So gas storage today has a real backup value. But it’s not clear yet what value it will have in the future, because technology is in constant evolution and the pace of change has proved unpredictable in the past.

In a way, you’re saying the future value of gas needs to be properly evaluated, which hasn’t been done until now.

The figures aren’t clear yet for renewable gas. There are a lot of studies but they all come up with different figures. If you take biogas, at the moment, production is very limited. In France, it represents only 1% of energy use. But some estimations indicate that in a couple of years, this could go up to 10%. And even though it’s a big increase, it’s only a small percentage of the total energy consumption.

So we have to understand the magnitude of the resources we’re talking about. Of course, new technologies will bring substantial changes to those numbers but at the moment it’s very difficult to have a clear assessment.

The jury is still out about future volumes of renewable and low-carbon gases. But the value they can bring to the wider energy system – has this been

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evaluated at all?

There is no definitive study yet. But in terms of decarbonisation, there is no discussion – switching to renewable gas brings unquestionable value. What remains to be carefully assessed is how to extract this value at sufficiently low cost for society. And that is still being assessed at the moment. There are some promising technologies to get carbon emissions from energy down to zero but the choices that will be made in the next 5-10 years will be decisive. And those need to be based on a careful cost-benefit analysis.

Existing gas storage facilities don’t need much upgrading to host hydrogen or renewable gases. And that is a big advantage in the overall cost-benefit analysis, right?

Yes, that will be an advantage, definitely. But there is an ongoing discussion about how power-to-gas and hydrogen installations should be considered when they are being used as a storage site. Are they a storage site or an energy generation facility? And that has an important impact on how they will be regulated.

The EU’s internal energy market rules stipulate that gas transmission assets should be separated from generation assets, along the principles of ‘ownership unbundling’.

But how do we consider power-to-gas installations? Are they a transmission asset or a small energy production site? Depending on the answer, unbundling rules will prevent some operators from owning these facilities or manage them.

These are all valid questions for which there are no clear answers yet.

What are the options? If power-to-gas facilities are somewhere between transmission and generation, could a separate category be created for them?

Well, that’s one possibility. Or more traditionally, regulators could decide that only transmission system operators should be allowed to manage power-to-gas facilities. Because at the end of the day, TSOs are the ones making the biggest investments in these kinds of projects.

So you think TSOs should be allowed to enter the power-to-gas market?

The answer to that question is not clear, it’s still being debated. I tend to be in favour of transition measures. If it’s not possible to create a third category or make an amendment to the third gas directive, then one option could be to allow TSOs or DSOs to manage these facilities during a transition period. And then make regulatory decisions later when the market has developed. Because power-to-gas is still a nascent technology so it may be wiser to wait before regulating this sector.

Do you see a risk that TSOs rapidly dominate the power-to-gas market and become monopolistic?

I think it’s a matter of fairness. There has been a similar discussion with hydropower plants. TSOs are only in charge of managing hydro facilities because they are part of the transmission network and transmission is a monopoly by nature. So TSOs are asked to manage the system for the benefit of all. But the...
moment they become the owners of capacity, this changes things and might distort the market. TSOs are not supposed to enter the power generation market, except for network safety reasons.

This is why I think a transition period where TSOs manage power-to-gas facilities could help grow the market in the beginning.

In the short term, switching from coal to gas brings rapid emission cuts. But over time, the EU aims for net-zero emissions. So how can policymakers design regulations that will ensure a carbon lock-in is avoided?

I do not see a big threat of carbon lock-in. The way ahead is pretty clear: calls for decarbonisation are so strong that all efforts are focused on making the transition as smooth as possible.

Everybody is preparing for a changing energy system. There are some clear signs from the big oil and gas majors who have started diversifying into renewable energies some years ago. And new synergies are being found between sectors to push the decarbonisation agenda – in energy, transport and even agriculture. And the interactions between those sectors will become stronger and stronger.

To achieve that, you have to stop thinking in terms of commodities – gas versus electricity – and start thinking in terms of energy carriers. And along that view, it doesn’t really matter anymore how the energy is being transmitted, as long as it comes from renewable or low-carbon sources.

Environmentalists have called on the Commission to stop funding gas infrastructure for fear that it will prolong fossil fuels. Are you saying they are misguided in this case?

I understand the fears of environmentalists and I understand where they see the risk. But I believe a transition by all means is necessary. So I think all support to gas infrastructure should be seen in a temporary perspective, for a transition period.

It’s obvious that we cannot jump straight into a fully decarbonised system so a transition will be necessary in any case. And that transition will not take 5 years, it will take at least 20-25 years. So we have to make the transition as smooth as possible, and at a cost which is affordable for society. And if natural gas, in the transition period, brings energy security at an affordable price, then why not?

But the question then is how much these new types of gas contribute to decarbonisation. Because biomethane and hydrogen, depending on where they come from, don’t have the same carbon footprint.

That’s true. There is also the issue of methane emissions. These don’t come only from fossil fuels, but also potentially from the future types of renewable or low-carbon gases. I’m thinking of blue hydrogen with carbon capture and storage but also from biomethane and even biogas. Leakages can happen at any point.

What the Commission often says is that if we don’t solve the issue of methane emissions, then basically all the efforts in reducing CO2 will be in vain. It’s such a big issue that it might compromise efforts made in other parts of the economy. And this is an issue that needs to be looked at because it won’t get solved automatically.
European gas storage sites have much to offer in the energy transition, providing a readily available platform to carry new low-carbon gases like hydrogen. What’s not clear yet is whether those gases can be produced in sufficient quantity to significantly cut carbon emissions.

The gas industry pitches its 1,200 terawatt hours (TWh) of available storage capacity as a potential benefit to Europe’s future low-carbon energy system.

“The question, of course, is what we’re going to put in that infrastructure over time,” said James Watson from Eurogas, an industry association. “And this is one of the questions we will need to get our heads around and really work hard to achieve,” he told participants at a recent EURACTIV event.

In the short term, gas storage sites can help decarbonise the power sector by providing seasonal storage during winter. They also provide an essential back-up for variable renewable electricity throughout the year. In the long-run, they could provide a platform to store low-carbon gases like green hydrogen generated from wind and solar power as well as biomethane produced locally from agricultural waste.

The problem is, estimates vary widely as to the sector’s ability to

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derive those clean gases in the quantities needed to support Europe’s goal of reaching net-zero emissions by 2050.

A recent industry-funded study has put the potential production of renewable gases at 270 billion cubic meters (bcm) per year by 2050, up from 122bcm on projections published the year before. The German industry association BDI even sees potential to import massive amounts of green hydrogen from sunny places like Australia, to the tune of 340TWh per year by 2050.

DECARBONISATION TARGET

Those projections are dismissed as exaggerated by environmental organisations, which came up with their own studies to dampen industry claims. And even the European Commission seems unconvinced by the multiplication of industry studies.

“I have never believed in all the studies,” said Klaus-Dieter Borchardt, a German national who is deputy director general the European Commission’s energy department. Although each study brings something valuable, their assumptions are often “not the ones we as policymakers would use,” he told participants at the EURACTIV event, held last month.

“What really matters is what we want to achieve – and that is decarbonisation,” Borchardt stressed, referring to transport, building and agriculture sectors, which are currently not covered by the EU’s carbon pricing system, the Emissions Trading Scheme (ETS).

“I think we should agree on a decarbonisation target for all this,” he told participants at the event. “And then you can develop the most suitable solutions,” he added, saying “that can be biomethane, green hydrogen or blue hydrogen” depending on the carbon footprint and different end-uses for these new types of gases.

Still, the issue of volume remains the biggest question mark. “Renewable gases – biogas, biomethane and hydrogen – are still in limited supply at the moment,” says Ilaria Conti, head of gas programme at the Florence School of Regulation.

“So one of the first things, is to evaluate the real potential of these renewable and low-carbon gases,” she told EURACTIV in an interview.

Taking biogas as an example, Conti said production is currently very limited, representing only 1% of energy use in a country like France. “Some estimations indicate that in a couple of years, this could go up to 10%. And even though it’s a big increase, it’s only a small percentage of the total energy consumption” in France, Conti remarked.

Eurogas has called for the introduction of a binding target for renewable and decarbonised gases, saying it will help bring higher production volumes to the market, like was done in the past for renewables in the electricity sector.

But EU officials have voiced doubts about the idea, saying a distinction must be made between the different types of gases, according to their varying carbon footprint.

The European Commission hasn’t made up its mind yet on the type of incentives scheme it wants to apply, and is looking into all options in view of its forthcoming Gas Package of legislation, expected to be tabled next year.

On the industry side, some are arguing for a regional approach to help bring the volumes up.

Groups of countries or regions should be encouraged to tap into the whole range of low-carbon energy sources at their disposal – whether biomethane in France or wind energy fuelling power-to-gas installations in Nordic countries, said Torben Brabo, the CEO of Danish gas TSO Energinet.

“Developments won’t happen everywhere at the same speed or using the same technologies,” Brabo pointed out, calling on regulators to leave enough flexibility for local and regional solutions to emerge.

“Regional developments should be preferred to a single uniform EU-wide approach,” Brabo said.

TRACING THE ORIGIN OF GAS

One of the key challenges for policymakers will be to find a way of tracing back the origin of these new low-carbon gases – and measure their carbon footprint.

The industry believes that can be achieved by putting in place certificates of origin, similar to what is currently done for wind and solar power in the electricity sector.

Digitalising infrastructure can also help. “By adding sensors in the infrastructure, you can know instantly what kind of gas is in the system. And that data can be shared with customers and other market players,” says Jan Ingwersen, from ENTSOG, the European Network of Transmission System Operators for Gas. “So we’re talking about a major digitalisation effort,” he told EURACTIV in a recent interview.

SILVER BULLETS AND UNICORNS

But while all options are open, EU regulators and environmental groups say the overarching decarbonisation objective should remain paramount.

“We shouldn’t focus on delivering green gas at any cost,” said Milan Elkerbout, a researcher at the Centre for European Policy Studies (CEPS) in Brussels. What matters most, he said, is to look at the end-use sectors that need to be decarbonised and, from there, assess the options available.

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And green gases will be attractive in some cases, but not always, he said. “We have to stop looking for silver bullets and unicorns,” added Lisa Fischer from green think tank E3G, pointing out that most studies to date have tended to focus on electricity and gas in isolation, pitting one against the other, without looking at synergies. “What we haven’t really had is a conversation that honestly looks at all the different solutions” available to decarbonise sectors like heavy industry, Fischer said. And potential solutions there exist also on the electricity side, she pointed out, citing demand-side response, grid interconnection and energy efficiency measures.

Klaus-Dieter Borchardt agreed on that point, warning the gas industry against the “mistake” of developing solutions in silos, without looking at other sectors like electricity. “You have to take a look at the full energy system,” Borchardt said, citing energy efficiency, demand-side management as well as the development of energy storage solutions. “We should not make the mistake of trying to find a niche for gas,” he added, but rather integrate gas into a wider energy system which puts decarbonisation as the overarching objective.

**IDENTIFYING END-CONSUMERS**

“The next mistake,” Borchardt warned, would be to develop green gases without the end-consumer in mind. “Especially when it comes to specialised gases, you can only develop them together with the appliances or the end-consumers,” the EU official said.

Once end-consumers are in the picture, the legal framework will fall into place naturally, he suggested, accepting that solutions will differ from one country to the other. “And based on that, we will find common rules, a common framework.” “Because I do not believe that with hydrogen or renewable gas, we will have widespread distribution, like for natural gas. It will be local, it will be regional, it will be where the consumption takes place,” Borchardt said, adding: “we won’t have positive effects if we believe that we will send hydrogen over long distances”.

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A demonstration plant in Germany that converts wind electricity into hydrogen is probably the most emblematic of a series of pilot projects that could radically transform Europe’s energy landscape in the coming decade.

Back in 2013, German energy utility Uniper achieved a world first – building a power-to-gas plant. Called WindGas, the facility became the first of its kind able to store wind energy in the natural gas grid.

“The name WindGas is because renewable electricity is generated from wind farms,” says Axel Wietfeld, Managing Director of Uniper Energy Storage. “At that time, it was clearly pioneering because it was the first power-to-gas facility in the world,” he told EURACTIV in a phone interview.

In the six years since it started operation, the 2MW capacity alkali-electrolyser at Uniper’s pilot plant has produced more than 8GWh of green hydrogen, Wietfeld says.

The challenge now is to scale up production in order to bring down costs and make green hydrogen competitive. “The focus now should really be on the next steps to scale up power-to-gas production, beyond the pilot projects,” says Wietfeld.

Green hydrogen is a 100% carbon-free source of energy which is widely seen as a central piece of Europe’s future low-carbon energy mix. Using an electrolyser, water is divided into its constituents – hydrogen and oxygen. When the electricity comes from renewables, the hydrogen can be labelled ‘green’ by opposition to ‘grey’ hydrogen which comes from splitting natural gas, a process which releases CO2.

As the EU strives for carbon neutrality, the European Commission firmly believes hydrogen will be
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among the only gases left in the energy mix by 2050. "Only e-gases, Power-to-X and hydrogen will be present there – for sure," said Miguel Arias Cañete, the EU Commissioner for climate action and energy, as he presented the EU's 2050 strategy for energy and climate change last year.

However, getting bigger volumes will take time and industry players say they need regulatory signals and incentives to move green hydrogen production beyond the pilot phase.

"As an industry, we are ready to invest in power-to-gas projects," Wietfeld says. "What is still an issue for us is the regulatory environment," he adds.

Power-to-gas is expensive. An electrolyser currently costs between €700-800,000 per megawatt, according to industry experts. This means a 10MW plant would equal about €7 million. And that’s just for the electrolysis. An entire facility, complete with all the piping, grid connections and electronics would cost about twice as much.

According to Wietfeld, a favourable regulatory environment at EU level could help reduce costs. But at the moment, he says network charges in Germany are penalising green hydrogen production. More generally, he says current regulations do not properly remunerate hydrogen producers for the services they bring to the wider energy system.

"Power-to-gas can de-bottleneck the electricity grid, therefore bringing system value that should be remunerated," Wietfeld says. "But at the moment, it’s the contrary which is happening: we are classified as end customers and therefore we have to pay renewable levies and taxes. And it’s just not fair that those taxes are being transferred from one sector to another. That is something that needs to be addressed both at EU and at national level."

In short, “we need a hydrogen concept for Germany and for Europe” in order to scale up production, Wietfeld says.

SUPPLYING PURE HYDROGEN AT SCALE

Scale is precisely what French company Storengy is trying to achieve. In Britain, the subsidiary of French utility Engie is spearheading a pilot project called Centurion at the Runcorn petrochemical site, where plastic is produced.

The plant currently runs on grey hydrogen but Storengy plans to replace that with green hydrogen obtained from renewable electricity. And storage is needed in order to supply the petrochemical site when it needs it.

“The plant does not run all the time and we need to run our electrolyser when electricity prices are as low as possible, so that’s why we need storage,” says Cécile Prévieu, CEO of Storengy. According to Prévieu, storage is a prerequisite to supply green hydrogen in large quantities. "Because in the supply chain, when you feed several large industrial sites, you have significant storage needs,” she explains.

According to Storengy, one of the strengths of the Centurion pilot plant is that it is connected to an existing logistics chain, which makes its realisation possible within a relatively short timeframe – less than 10 years.

The petrochemical plant is already connected to a gas storage site by an ethylene pipeline which is no longer in use and can easily be converted to carry 100% hydrogen. That allows it to tap into the hydrogen reserve at any moment according to its needs, Prévieu says.

The next big challenge is to reach the critical size needed in order to reduce costs. “The idea is to have large-scale production that reduces fixed costs and produces competitive green hydrogen by comparison to grey hydrogen obtained by steam reforming,” Prévieu said.

This is where Prévieu believes policymakers can help – by drawing a line between green and grey hydrogen and issuing certificates of origin to reward the renewable sort over the fossil fuel sort. And for that, she says a clear definition is needed of what is meant by green hydrogen.

“Customers need to have a guarantee that what they are buying is green,” Prévieu explains.

“The sooner we have a terminology, the faster we can have a market for green hydrogen that starts emerging,” she told EURACTIV, adding “there has to be an upstream control of hydrogen production processes to certify their origin.”

SMALL-SCALE BIOMETHANE STORAGE: LILIBOX

While Centurion focuses on industrial-scale hydrogen storage and delivery, another pilot project run by Storengy focuses on small-scale storage of locally-produced biogas.

Called Lilibox, the project involves liquefying biomethane produced locally from agricultural waste and storing close to the production site in the form or Bio LNG, which can then be used to power trucks and buses.

The project is in fact no longer a pilot and is about to begin commercial operation. “This is a start-up that will market its products at a competitive price from June 2019,” Prévieu says.

“It involves liquefying biomethane that is produced in excess and cannot be injected immediately into the network at the time it is produced,” she explains.

Once liquefied, biomethane is stored in tanks where it can be kept, usually for a few days or weeks. The

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biogas can then either be reinjected into the local network or used as fuel – typically for local bus services or to power the trucks of nearby farms.

The benefits are mainly local, Prévieu says, but they’re significant. Storing biomethane prevents farmers from having to flare their excess production, which releases carbon. According to Prévieu, it also improves the profitability of anaerobic digestion units at local level, increasing the productivity of biomethane plants by 10-25%.

When it is reinjected into the local gas network, the Bio LNG also prevents network congestion problems at local level, Prévieu points out, reducing the need for local operators to invest in new network.

“The Lilibox acts like a buffer, for example at night or in the summer when there is less consumption,” Prévieu explains, saying this can save millions of euros in avoided network development costs.

**UNDERGROUND SUN STORAGE**

The fourth project, called Underground Sun Storage, is the most unexpected – at least, according to its designers.

It all started in 2013 when Austria’s largest gas storage company, RAG Austria AG, opened an experimental underground hydrogen storage site for research purposes. The initial objective was to store hydrogen produced from solar energy in a depleted reservoir and test the infrastructure’s resistance to corrosion.

It’s when they tried injecting liquid CO2 in the reservoir that the researchers got unexpected results.

“We discovered that by adding CO2 in addition to hydrogen in the reservoir, we were able to recreate the natural process of generating methane, or natural gas,” says Stephan Bauer, Project manager at Underground Sun Storage.

Of course, the production of methane with hydrogen and CO2 was described in the literature, Bauer says. “But still we were surprised to see it happening for real. It was a bit magic, I have to say. It would be nice to say it was planned, but I wouldn’t dare say that because it was not,” he told EURACTIV.

A key difference with natural gas, however, is that the CO2 is contained in a closed cycle and does not add to greenhouse gas emissions. “What took millions of years, and earned gas a bad name – fossil – we can now speed up and recreate in a matter of weeks,” Bauer says.

The project’s main objective is to generate hydrogen from solar energy during the summer when sunshine is abundant in Austria. Once converted into hydrogen, solar power can then be stored in a reservoir and injected back into the grid during winter when demand for space heating increases.

“Of course, there are alternative storage technologies, like batteries. But these usually last for a few days, they cannot provide long-term seasonal storage during the whole winter,” Bauer said.

The price of an electrolyser is a big cost parameter, which means storing solar energy as a gas is not commercially viable for now. But it’s not the focus of the project, Bauer explains. “In the future, the challenge is to have a flexible optimised process” so that the stored hydrogen can provide back-up for electricity in the winter, he explains.

According to Bauer, the project is still at an early stage and it would be premature to make suggestions about what’s needed from a regulatory perspective at EU level. But like Uniper and Storengy, Bauer says regulatory issues will need to be addressed at some point.

“This is a process where clean renewable energy is transformed during summer time and being stored for use in winter time, when the demand is highest. So this is a service. And you need to remunerate that service,” he says.

A big question for regulators, Bauer says, is how green hydrogen should be viewed when it comes to CO2 pricing under the EU Emissions Trading Scheme. “Another is who is in charge: is it the grid operator or should this be left to a market-based operator?”

Once these questions are addressed, the next big challenge will be to make hydrogen production and storage a fully tariff-free regulated process which is ready for the market.

“There are lots questions out there, and the biggest threat I see is politics,” Bauer said.
The European citizens increasingly demand energy that is greener and available when needed. The stated objective of political leaders in Europe is higher energy efficiency, higher share of renewable energy sources in energy-mix, and carbon reduction.

Lubor Veleba is President of Gas Storage Europe (GSE) and Board Member of Gas Infrastructure Europe (GIE).

This shift of focus from competition to decarbonisation has started in the electricity sector but other sectors already follow. The challenge for that to happen: a greater need for energy flexibility with energy storage as the main provider (read more here).

Against this backdrop, European gas storage operators are preparing to be part of the future world of energy and even be the driving force as storing the excess of renewable sources will foster their deployment (ending risk of curtailment). Storage operators around Europe now run demonstration projects, many on a hundred MWh scale, including power to gas, power to fuels, power to heat, methanisation or storage of pure hydrogen.

Gas storage facilities were built as an integral part of the natural gas systems, together with transmission and distribution systems, and for decades provided the primary asset of gas systems – flexibility and ability to store in different timeframes and on large scale. In fact, today, gas storage capacity in the EU is around 1000 TWh enabling to store gas for periods

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ranging from hours to several months. This existing storage capacity can be used in future for various green and decarbonised gases. Once the gas system adapts the surface parts to these new gases, gas storage brings only little additional complication with its subsurface part. Storage operators believe that gases such as biomethane and synthetic methane would be acceptable also for all types of gas storages and pure hydrogen would work for cavern storages.

Gas storage today has a unique position in that it keeps strategic options open for policy makers. In parts of Europe where today’s agenda is dominated by renewable energy sources and zero-carbon economy, gas storage can provide long range energy storage thus complementing the battery technology through technologies such as power to gas. Where policy makers still need to focus more on removing lignite from the energy mix, gas storage can be instrumental in supporting natural gas as an immediate solution.

Gas storage has been helping end-users to decrease cost of transmission, provide insurance against technical downtimes, against interruption of supply and against price shocks in its traditional natural gas sector. In the last several years, storage operators struggled to cover their costs as the summer winter spreads of futures gas prices on traded gas markets – a typical storage valuation approach – shrunked and as the system and insurance values of storage saw little if any discovery by markets.

The system and insurance values of gas storage, or in the words of economists positive externalities, result from benefits reaped by other gas market participants and other sectors such as electricity. That is why we need a new regulatory approach in Europe that would recognise these additional values. Governments and national regulators would be foolish to lose gas storage assets and should seek a solution how to bring some of this hidden value to storage operators, in the words of economists internalise these externalities.

In fact, to quantify the cross-sectoral impacts of a reduced gas storage capacity, GIE has recently commissioned a study with Artelys which preliminary results were presented at Madrid Forum last week. The study analyses the ability of the electricity system to meet the demand with a reduction of gas storage capacity at EU level. This allows the capacity value of European gas storage capacities to be evaluated for the first time. In this analysis, and based on ENTSOs joint scenario assumptions, we observed that in 2030 additional operational expenses of EUR 1 billion per year arise from about 10% reduction in gas storage capacity as more expensive power generation units need to dispatch and an electricity demand curtailment arises already from 20% of gas storage capacity reduction.

With no changes in the regulatory framework for gas storage market, the market will lead to sub-optimal level in terms of storage capacity. As the above mentioned analysis indicate, further capacity reduction puts the security of supply and resilience of electricity and gas systems at risk and the opportunity to go through the energy transition at the optimal for society cost may be lost.

A range of regulatory approaches is available according to the study GIE conducted with FTI-CL Energy on the measures for a sustainable gas storage market. The relevance of the study lays in bridging the EC’s market-based approach to its long-term vision and calls for a revisit to the regulatory framework.

Gas storage can be the missing element in the future world of decarbonized energy if we get it right and, by changing the fundamentals on the supply side, become the driving force in development of the decarbonised energy world.