argusmedia.com

Argus White Paper:

Power market winter outlook 2019-20

Higher nuclear and renewable power generation could limit the call on thermal plants this winter, particularly in northwest Europe where forecasts indicate a milder, wetter winter than normal. Coal-fired generation remains less profitable than gas in many countries, but will still be required to meet demand during periods of cold weather and low renewable power output. But these periods are becoming increasingly infrequent, raising questions as to the viability of coal-fired plants in many countries.

Nuclear winter

The European power markets head into winter 2019-20 with fewer of problems that have dogged nuclear plants and limited generation during the past few winters.

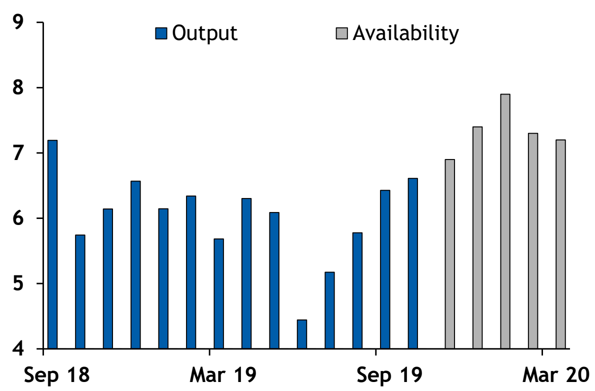
France provided a short-lived scare in September when nuclear safety authority ASN expressed concerns over several plants, but it has since said that it does not expect any of the impacted plants to require additional maintenance outages as a result.

France, Belgium and the UK are all expected to have higher nuclear availability this winter compared to last year. UK nuclear availability is now scheduled to average 7.3GW over November-March, compared with average output of 6.2GW during the same period last winter.

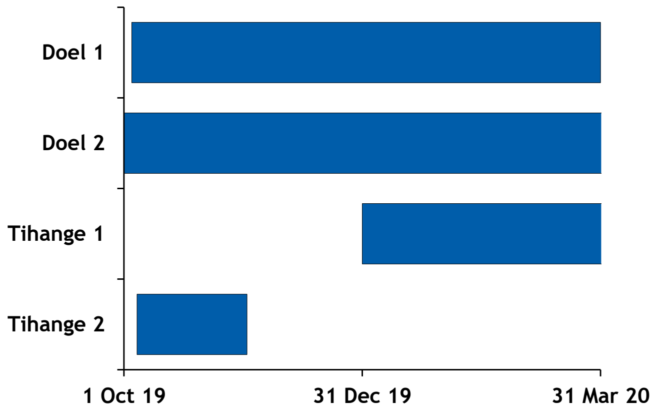
Both units at Dungeness B have been further delayed, to 24 January from 29 November and to 4 February from 10 December. The Hunterston B reactor 3 (unit 7) is also off line but due back before the coldest period begins.

All three units have been on long-term outages since 2018 which have been repeatedly extended. But even if they were all further delayed for the entire winter, availability would still be higher on the year at 6.6GW. The Hunterston B reactor 4

UK nuclear output and future availability *GW*



Belgian nuclear unavailability winter 2019-20



Generation Fuels

illuminating the markets

(unit 8), which was also on a long-term outage, has already been allowed to return, which may be a positive sign for the prospects of B7.

France is expecting much higher nuclear generation this winter than last, despite a recent extension to outages at the Flamanville plant.

In France, nuclear availability is scheduled to be 49.53GW in the fourth quarter compared to 48.23GW last year. And in the first quarter of 2020 availability is scheduled at 57.23GW, up from 41.13GW in the same period last winter.

Last year, as much as 5GW of Belgium's 5.9GW nuclear fleet was off line in the fourth quarter. This year, some plants will still be unavailable but total availability will be much higher. The 1GW Tihange 1 unit will be off line from 31 December to 10 July, while 900MW at Doel will be off line throughout the winter.

Germany, Switzerland and Sweden are the exception — nuclear capacity will be lower with the permanent closures of the 1.4GW Phillippsburg 2 plant in Germany and the 852MW unit 2 at Ringhals nuclear power in Sweden by the end of 2019, reducing installed nuclear capacity to 8.1GW in Germany and 6.8GW in Sweden. But the other plants are scheduled to remain available throughout the winter. German nuclear generation averaged 7.5GW in the fourth quarter of 2018 due to some outages and 9.13GW in the first quarter of 2019.

In Switzerland, nuclear power plant availability will also decline as the 375MW Muhlberg nuclear plant is scheduled to close at the end of this year, leaving Swiss nuclear installed capacity at 2.9GW at the beginning of 2020.

Offshore wind adds to supply

Higher nuclear availability will limit the amount of residual demand thermal generation is required to meet. Overall thermal generation could also come under pressure from rising renewable installations, particularly in offshore wind.

The UK will have added around 2GW of new offshore capacity this year to increase its total to 10.2GW, Germany has added around 1.2GW of offshore capacity and Denmark has added around 407MW of capacity offshore. Belgium also added a 370MW offshore wind farm earlier this year.

And offshore load factors are steadily rising as newer farms come on line — load factors were above the historical average last year, even as wind speeds were at average, as the newer turbines tend to have higher load factors.

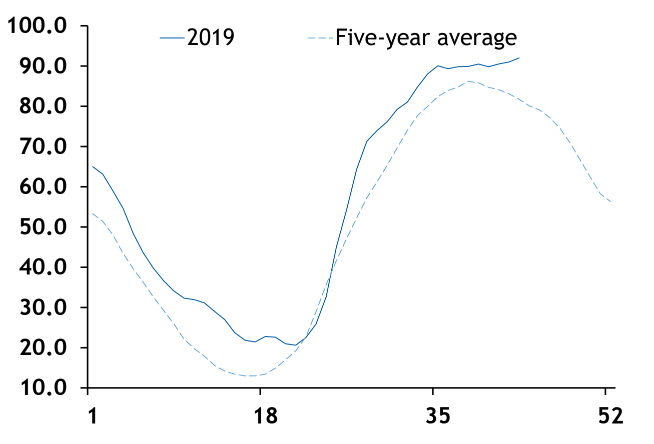
German onshore wind capacity growth has been slower than expected this year. Germany added around 2.24GW of new onshore wind capacity in 2018. The country has added around 507MW of new capacity from January until the end of September this year and is expected to enter next year with 1-1.5GW of new capacity, according to sector forecasts.

Solar power generation has also risen on the year, peaking at an average of 8.96GW in June. Faster solar additions have also supported total generation. Germany added around 2.72GW of solar photovoltaic (PV) capacity in 2018 and additions have also exceeded 2GW from January to end of August, according to the most recent data from Bnetza.

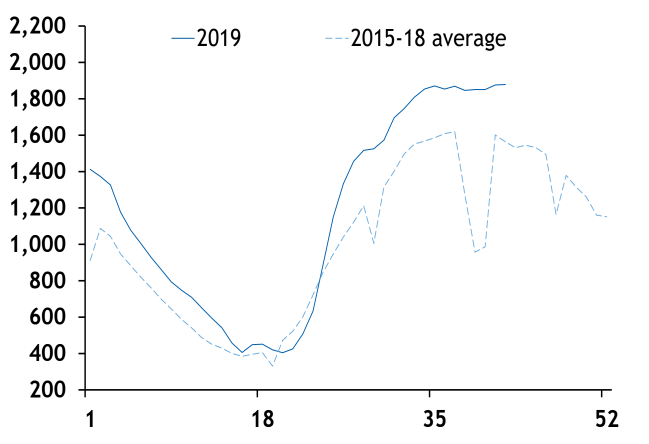
Capacity additions have accelerated in recent months in mainland Spain, as companies that won 3.9GW of solar PV and 4.1GW of wind capacity in two auctions in 2017 approach the 31 December 2019 deadline to bring units on line.

Solar PV additions totalled 1.54GW in January-September, bringing the total installed capacity to 6GW, while wind recorded a 524MW increase to 23.61GW. Spanish grid operator REE said early this year that it expected as much as

Swiss hydropower stocks *pc*



Austrian hydropower stocks *GWh*



6GW of new renewable capacity to connect to the grid by the end of this year.

Hydro situation diverges

The other supply factor that could limit thermal generation is hydropower. Hydropower reserves in the Alpine regions remain above last year's levels and well above long-term averages. In France, hydropower reserves stood at 73.8pc of total capacity at the end of week 42, above last year's levels and the long-term average.

Swiss hydropower stocks were at 92.5pc of total capacity at the beginning of week 44 and the highest level for the period since 2000. In Austria, hydropower reserves totalled 1.87TWh at the end of week 43, above the 2015-18 average.

Expectations of higher hydropower generation this winter have narrowed Alpine winter spreads to Germany year on year, despite expectations of lower Swiss nuclear power plant availability after the 375MW Muhlberg nuclear plant closes at the end of this year.

In the Nordic market area, hydropower stocks were at 79.3pc of total capacity at the end of week 43 and below long-term averages. But Nordic winter prices in the Nasdaq power exchange remain below equivalent German winter contracts.

Water levels on the Rhine are also higher than last year, reducing the cost of barging coal to south German power plants. But Spain is an exception, with hydro storage levels below seasonal norms all summer.

Hydro stocks declined for 20 consecutive weeks from the end of May to mid-October, reaching a 20-month low capacity of 32.5pc, 8.4-9.5 percentage points below historical averages.

But hydro reserves started to increase towards the end of October, and could further recover in November based on forecasts of strong rainfall in some hydro-rich regions. Orense, part of the Mino-Sil river system in the northwest, was predicted to record 211mm in November, more than double the 97mm norm for the month.

On the demand side, forecasts from Meteo France, Germany's DWD, the European Centre for Medium Range Weather Forecasts and the UK's Met Office are in agreement that there is a high chance of a mild, wet winter in northwestern Europe, limiting power demand for heating and boosting hydro generation. But forecasts indicated a higher chance of a colder and drier than normal winter in southern Europe, particularly Turkey, the Balkans and Italy.

Demand has continued to trend lower this year in most countries. UK system demand was consistently lower on the year in every month of summer 2019. Embedded generation and a trend of increasing energy efficiency weighed on high-voltage demand in many markets.

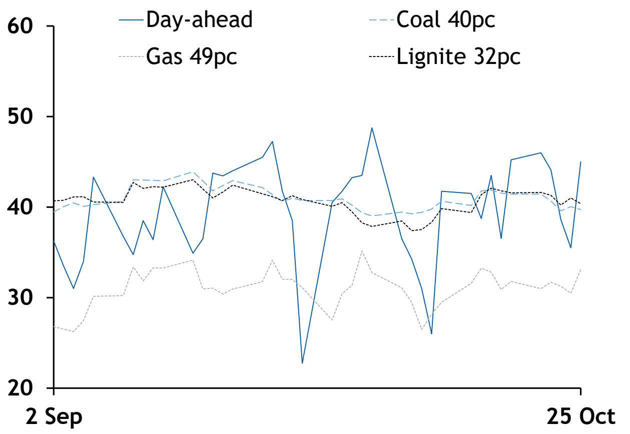
Old King Coal dethroned

The space that remains to be filled by thermal generation is likely to see higher gas burn year on year, with coal pushed further into the margins.

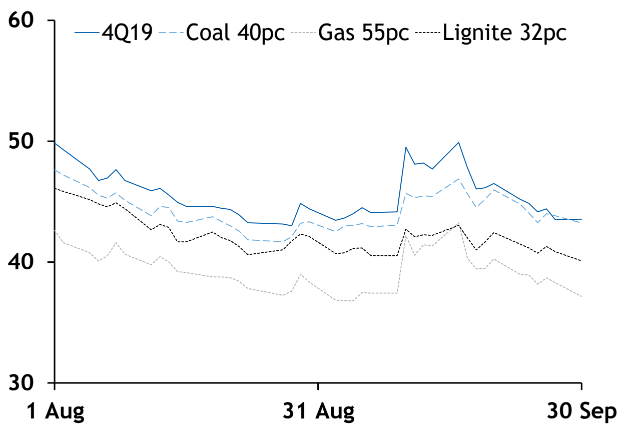
German coal-to-gas fuel switching is supported when gas prices move below the levels at which 55pc-efficient gas-fired plants can compete with 40pc-efficient coal-fired units. Working day-ahead clean spark spreads for a medium efficient unit have averaged €7.38/MWh so far this year, compared with €1.02/MWh clean dark spreads for a 40pc-efficient coal-fired unit, *Argus* data show.

Gas-fired generation has averaged around 4.93GW so far this year, while coal-fired output was at an average of 4.82GW. This compares with last year when coal-fired generation was deeply embedded in the German merit order at an average

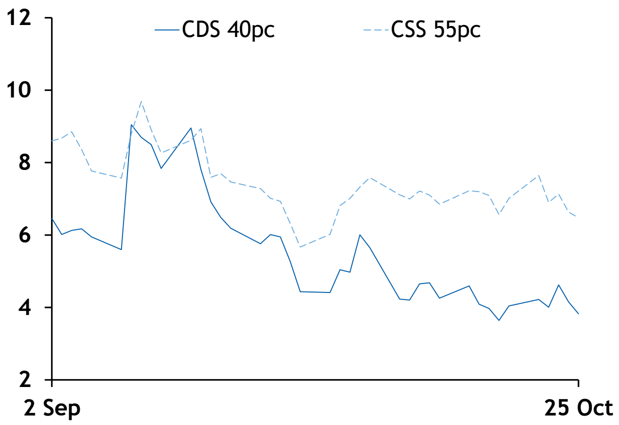
German day ahead vs breakeven costs €/MWh



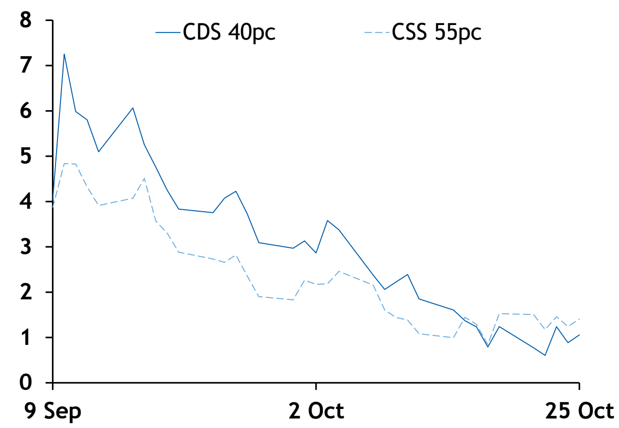
German 4Q19 vs breakeven costs €/MWh



German fuel-switching potential November *€/MWh*



German fuel-switching potential December *€/MWh*



of 8.24GW and gas-fired units were at the margin of the mix, producing an average of 3.86GW.

So far this year, a switch in German generation economics following lower NCG gas hub prices has lifted generation from gas-fired plants above that from coal-fired units consistently from June onwards.

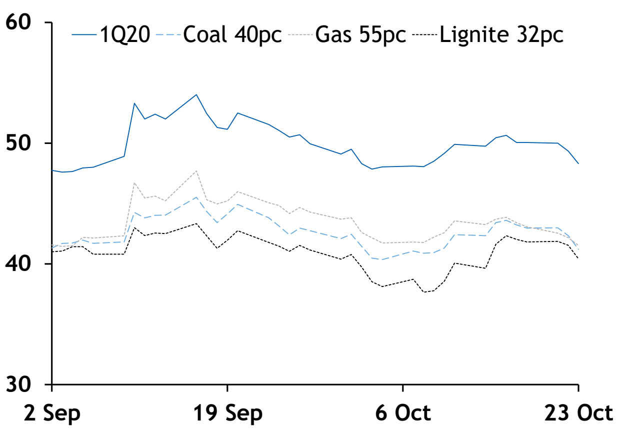
Germany has around 8.5GW of installed gas-fired generation capacity available to the wholesale power market, while coal-fired capacity available to the wholesale market stands at around 20GW. With gas-fired plants already running at load factors of 78pc this month so far compared with 22.6pc for coal-fired, any significant uptick in demand for thermal power will have to lead to a rise in coal generation, given the lack of additional gas capacity left in the wholesale power market to come on line.

France could see more winter gas burn year on year as lower PEG Nord gas prices against API 2 coal swaps have pulled the profitability of power sector gas burn above that of coal burn for this quarter. Clean spark spreads for a 55pc-efficient gas-fired plant and fourth-quarter 2019 base-load delivery expired at €18.57/MWh, €4.26/MWh above the corresponding clean dark spreads for a 40pc-efficient coal-fired plant.

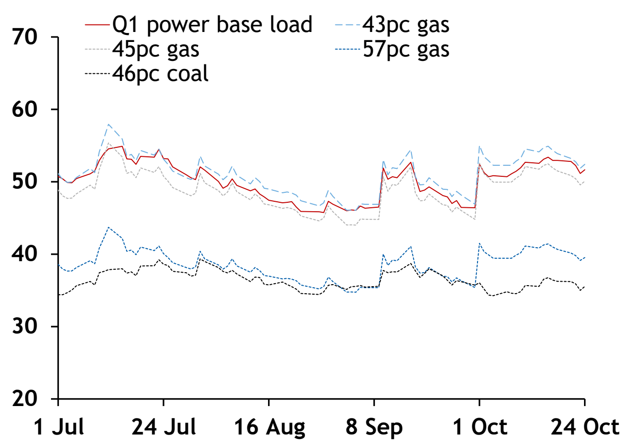
But the spread narrows considerably for the front quarter, with first-quarter 2020 55pc sparks holding on average €0.06/MWh above 40pc darks throughout their assessment so far.

French day-ahead clean spark spreads for a 55pc-efficient gas-fired plant and base-load delivery averaged €5.96/MWh below the equivalent 40pc clean dark spreads over the fourth quarter of 2018 but €0.29/MWh above the first quarter of 2019. French gas burn averaged 5.1GW in the fourth quarter of 2018 and 6GW in the first quarter of 2019, while

German 1Q20 vs breakeven costs *€/MWh*



Dutch front quarter vs breakeven costs *€/MWh*



coal output averaged 696MW and 317MW, respectively, over the same quarters.

The Netherlands' highly efficient coal-fired plants are better placed than most but still have higher break-even costs than a 58pc-efficient gas-fired plant.

Break-even costs for 46pc coal-fired plants have held decisively below those of even 57pc-efficient gas-fired plants for the first quarter of 2020 throughout the contract's assessment as the front quarter so far.

But while coal margins were also well below gas in the merit order at the start of the fourth quarter of 2019's assessment as the front quarter, this became tighter towards delivery, with costs for 46pc-efficient coal-fired generation eventually expiring at €35.71/MWh, above those for 57pc-efficient gas-fired generation of €35.38/MWh.

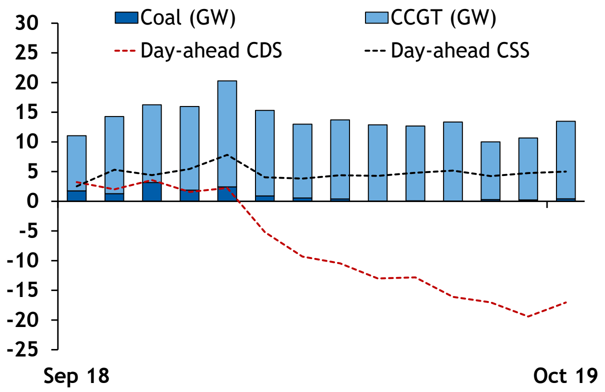
This suggests that Dutch coal-fired plants could ramp down before some high-efficiency gas-fired units on days with low demand and high renewable generation over the period. This differs from last year, when higher TTF gas prices against API 2 coal swaps and lower EU ETS prices held coal break-evens well below 57pc gas throughout the fourth quarter of 2018's assessment as the front quarter.

In Italy, highly efficient gas will remain more profitable in November than its most efficient coal-fired plants. But a 40pc coal-fired plant remains just ahead of a 55pc gas-fired plant in terms of profitability for November. The 40pc clean dark spread for the front month has averaged €17.97/MWh so far this month, only €0.51/MWh higher than the corresponding 55pc clean spark spread.

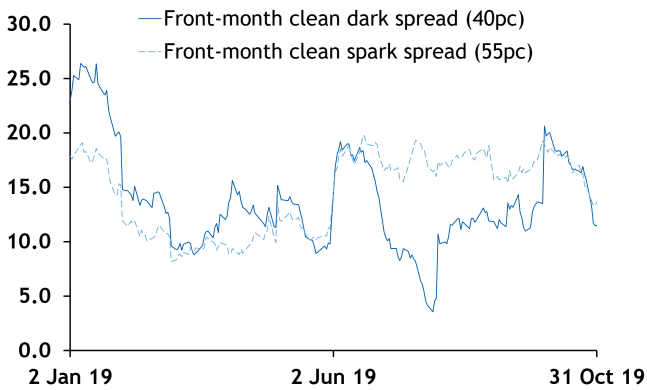
But in delivery so far in October, the 55pc-efficient gas-fired plant has been ahead, with clean sparks of €23.39/MWh based on PUN prices, compared to €14.49/MWh for a 40pc coal plant.

Coal generation in Italy remains essential, especially in the Sardinian market zone, keeping some plants on line regardless of economics.

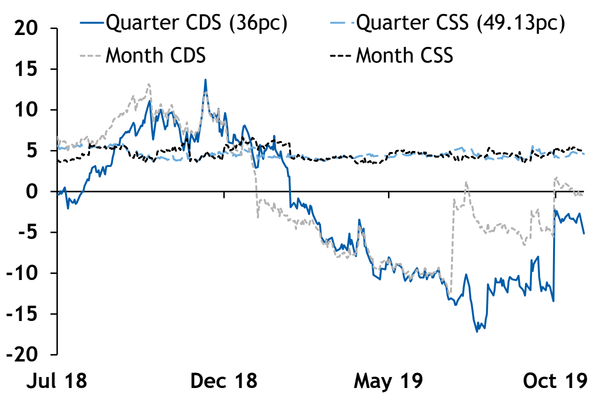
UK coal, gas-fired margins and output *£/MWh*



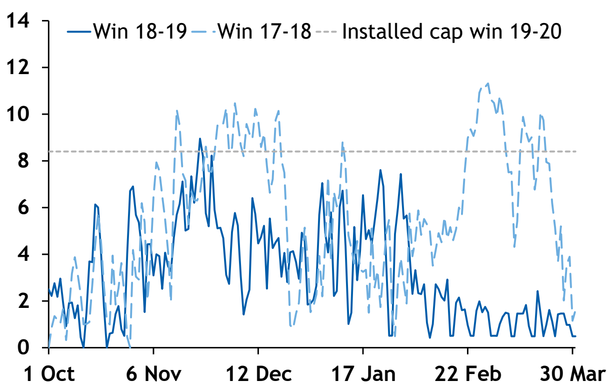
Italian front-month dark vs spark *€/MWh*



UK front-month, front-quarter generation spreads *£/MWh*



UK peak coal gen and installed capacity *GW*



Post-fuel switching

The UK and Spain are effectively "post-fuel switching" markets, with the carbon price floor in the former and coal tax in the latter adding cost to coal-fired generation, beyond the EU ETS scheme and making almost all gas plants more profitable to run. Both markets also have relatively old, inefficient coal-fired plants, increasing their disadvantage against fleets of much more modern combined-cycle gas turbines.

UK clean spark spreads are much wider than clean darks, but there is limited room for further fuel switching as coal has already fallen to extremely low levels.

Clean spark spreads are only slightly lower than they were last year, as lower net imports and coal-fired output could keep gas-fired output at similar levels this year, despite the outlook of higher wind and nuclear generation and weaker demand. Coal-fired output averaged just 1.7GW last winter, and has been close to zero this summer.

Coal-fired output reached all-time monthly lows of 343GWh in May and 341GWh in August in peninsular Spain. In several days over the summer, Portuguese utility EDP's 562MW Abono 2 facility was the only one of 25 individual coal-fired power units in mainland Spain to operate – and mainly because of technical constraints in the distribution network in the northern region of Asturias.

Coal was displaced in the power system to such an extent that even Spanish utility Endesa, a strong advocate of the fuel, announced that it would discontinue its coal-fired production in peninsular Spain, although it did not commit to a target date.

But forward prices suggest coal-fired generation this winter will still be profitable, with an outlook of increasing output over the next few months and possibly tight competition with gas for the expected merit order in the first three months of 2020.

Front-month clean dark spreads for a 36pc-efficient coal-fired plant in Spain averaged minus €4.14/MWh for October but was positive for November at €1.45/MWh over 1-30 October. And clean dark spreads were averaging €3.64/MWh for December and €4.80/MWh for the first quarter over that same period.

Inefficient gas plants will see some competition from coal in the first quarter at current prices. Clean 36pc dark spreads' discounts to corresponding clean spark spreads for a 49pc gas efficiency were expected to narrow consistently in the coming months, from a strong €13.13/MWh for October to €7.90/MWh for November, €4.58/MWh for December and just €1.84/MWh for January-March 2020.

Coal capacity lower

Coal burn will also be limited as capacity is lower than last year. In the UK, the Cottam plant closed in the summer, reducing installed coal capacity to 8.4GW , and will fall to 5.3GW by March 2020 when Aberthaw and Fiddler's Ferry shut.

German lignite-fired capacity entered October 757MW lower year on year as the 465MW Janschwalde E and 292MW Neurath units entered the lignite reserve and are no longer available in the wholesale power market.

Coal-fired capacity available this winter is also lower on the year as around 1.4GW closed at the end of March this year, leaving German total coal-fired capacity at around 20GW.

The 650MW Hemweg 8 coal-fired power plant in the Netherlands is to close on 1 January 2020 as part of the country's efforts to meet greenhouse gas emissions targets, further limiting scope for coal-fired generation this winter.

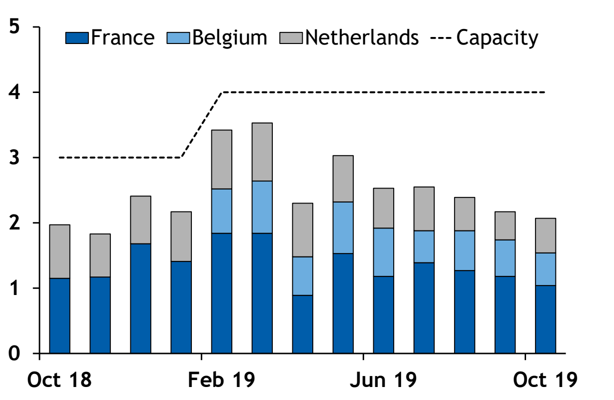
Declining installed coal capacity means the power sector's room to shift to coal is more limited compared with previous winters. Power will likely follow gas to a greater extent than previous years, and any gas price spikes similar to those in winter 2017 could have an even larger effect on power.

Pricing in late winter gas risk

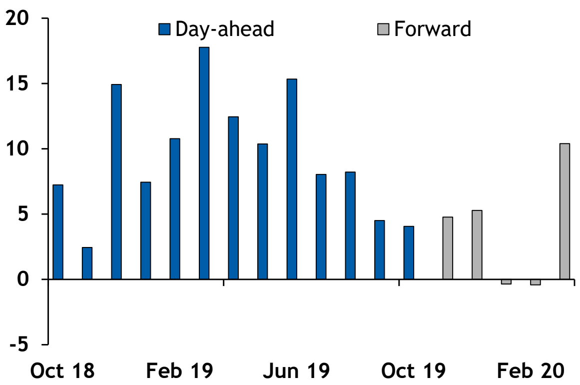
One striking factor is the wider first-quarter premium to the fourth quarter than in recent years. While the first quarter is normally above the fourth quarter contract due to lower temperatures in the quarter and on the risk of gas storage levels running low by later winter, the premium is wider than in at least the last decade.

When the German fourth quarter 2019 contract expired, it was €4.88/MWh below the first quarter 2020 contract. When the fourth quarter 2018 contract expired, it was at a €0.28/MWh premium to the first quarter of 2019. For winter 2016-17, the fourth quarter was at a €0.69/MWh discount to the first quarter at expiry and in winter 2017-18, the fourth quarter was at a €0.21/MWh discount to the first quarter at expiry.

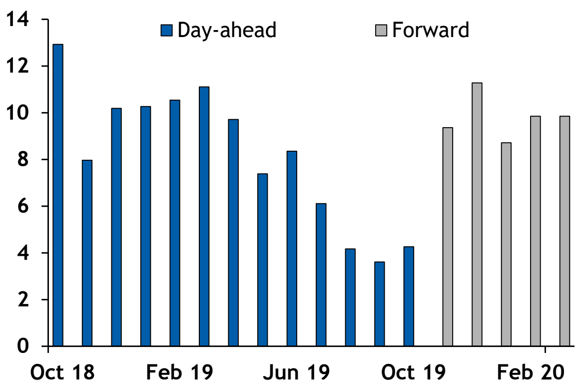
UK imports from continental Europe GW



UK-France spreads €/MWh



UK-Netherlands spreads €/MWh



This reflects the position of the gas market where the first-quarter contract holds a wide premium over the remaining months of the fourth quarter, partly over concerns over the possibility of disruption to Russian gas supplies in the new year as a result of transit negotiations with Ukraine.

This is particularly evident in Italy, which is heavily reliant on Russian gas supplies via Ukraine. The PSV contract for the first quarter of 2020 has averaged €20.24/MWh in October, compared with November PSV averaging just €17.51/MWh. The front quarter was at a premium of just €0.66/MWh over November in the same period of 2018, *Argus* data show.

On 28 October, the Italian first-quarter 2020 power contract closed at €59.75/MWh, while November is at €52.95/MWh and December at €56.00/MWh.

But if gas supplies remain stable, prices in the first quarter of 2020 could deliver at levels much closer to where the fourth-quarter contract expired and where November and December are trading at. High levels of gas storage and forecasts of a mild winter in northern Europe mean that if flows from Russia remain at normal levels, the gas market could be oversupplied. Gas prices could fall to incentivise more gas-fired generation but in markets like Germany, there will likely be only limited room to increase demand given the already high load factors.

Cross-border flows change on new and old borders

Cross-border power flows are also likely to change. New interconnectors have come on line between Denmark and the Netherlands, and the UK and Belgium, since last winter.

On existing borders, net power flows may be the reverse of last year on the France-Belgium border, with prices implying net exports from Belgium to France this winter, and from Italy towards southeastern Europe, with Italy at a discount to the regional benchmark Hungarian market for the fourth quarter and the first quarter.

New borders: Nemo and Cobra

The 1GW Nemo interconnector linking Belgium to the UK started up at the end of January, adding more flexibility to the Belgian power system in the form of import and export opportunities. The fourth quarter 2019 contract expired at a €1.32/MWh discount to the UK, while the first quarter 2020 has averaged €3.17/MWh below throughout its assessment so far, suggesting that Belgium is likely to be a net exporter to the UK this winter over the new link.

The commissioning of the 700MW Cobra interconnector between the Netherlands and Denmark in September has introduced additional flexibility to the Dutch power system for this winter. The first cross-border capacity auction for the link for November delivery allocated 150MW in each direction at an average price of €2.64/MWh for Danish-Dutch capacity and €0.88/MWh for Dutch-Danish capacity, suggesting that the Netherlands is likely to be a net importer over the link at least for the month ahead.

However, the 400MW Kriegers Flak cable between Denmark and Germany has been delayed, with commercial operations now expected to start at the end of the first quarter of 2020 rather than in January.

Old borders, new tricks

Germany has returned to a net exporter position to central western European (CWE) markets after being a net importer to these countries during the spring and summer periods, but German exports have so far this quarter been lower on the year.

Germany has been a narrow net exporter to the Netherlands and France in October according to cross-border allocation data from Entso-e – which includes day-ahead, intra-day and long-term allocations.

Germany has been a net importer of Dutch and French power on some days in October when German wind output was low and given lower generation costs in these markets. Prevailing price spreads show narrower winter spreads between Germany and the Netherlands for base load but they are even lower for peak load.

Higher nuclear power plant availability in the CWE region and higher hydropower conditions year on year — combined with Germany's lower base-load capacity — has also narrowed Germany's discount to France, Switzerland and Austria for base load and peak load year on year.

This suggests that Germany's exports potential could be lower on the year this winter should weather and neighbouring base-load capacity forecasts materialise, which in turn could support some imports into Germany on low renewable days.

Output from Spanish fossil fuel plants could also be limited by higher French power flows from mid-November, when French power grid operator RTE expects to conclude maintenance works on the 1.6GW Argia-Hernani interconnector.

Cross-border capacity was limited during most of the summer because of an incident on an electrical line linked to that interconnector. This led to no monthly capacity being offered in the France-Spain direction for August or July at the cross-border auctions run by the Joint Allocation Office. Auctioned capacity rose to 70MW for September, 470MW for October and 950MW for November.

Auctioned prices for November, however, cleared at similar levels — €3.89/MWh for France-Spain and €3.51/MWh for the opposite direction — suggesting greater market uncertainty this year over the outcome of delivery power price spreads between the two countries for November.

French day-ahead prices are typically at a discount to Spanish prices. But the last time France delivered at a monthly average premium to Spain was in November 2018, due to lower-than-average minimum temperatures in France and limited nuclear generation in the CWE region, particularly in Belgium. The French premium averaged €6.18/MWh in November last year. France also ended at a monthly premium to Spain in November 2017, at €4.08/MWh.

Forward prices over 1-30 October indicate Spanish prices at a €0.24/MWh average discount to France for November but at a €0.66/MWh premium for December. The average spread for the first quarter was a €1.62/MWh Spanish discount.

Italy as exporter

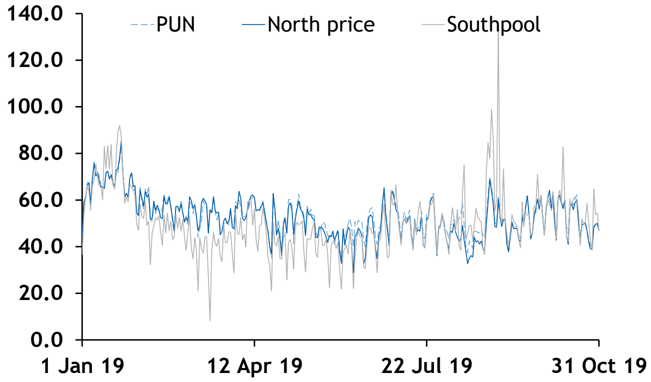
Lower gas prices have put pressure on the Italian north power zone price, where the large part of national gas capacity is installed. This helped to turn Italy in a net exporter to Slovenia since July, along with higher power prices in east European markets. The north price has delivered at an average of €49.80/MWh since 1 July, at €1.84/MWh discount to PUN and €4.38/MWh lower than the corresponding Slovenian spot price. Italian net exports were at an hourly average of 180MW in the third quarter of 2019 compared with net imports of 347MW in the same period a year earlier. In October Italy has exported at an hourly average of 174MW, according to Entso-e.

SEE the premium market

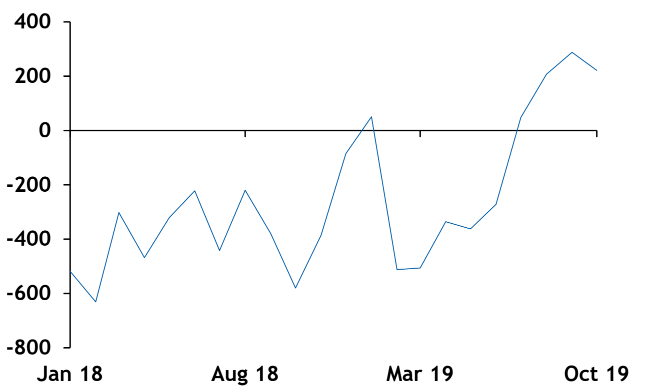
Italian exports via Slovenia could continue into the winter as prices in the eastern European markets are markedly higher year on year.

Romania has emerged as the premium market in southeastern Europe this year and price driver for the region this year since the regulated power market was reintroduced in March and a 2pc turnover tax was imposed on producers at the beginning of this year. Spot and forward prices have persisted at premiums to regional markets, as strong CO_2 prices and hydropower holding at a seven-year low recently have pushed the country to a net importer position.

Italy-Slovenia power prices *€/MWh*



Italy-Slovenia power flows *MW*



The Opcom spot is on track to deliver at a small premium to the Hungarian Hupx on average over the entire year for the first time on record, largely driven by the €2.35/MWh premium throughout the third quarter.

Bulgaria could also provide regional price upside early next year, as state-owned generators have sold almost no power for delivery next year, causing concern in particular for trading companies with domestic retail portfolios, while portions of cheaper generation are excluded from the free market, leaving only more expensive plants in the day-ahead market.

The 2GW Kozloduy nuclear plant's share of the regulated market increased to nearly 27pc this year, and while hydro-focused Nek's share is smaller, at around 5pc, reservoir stocks are at a four-year low, so the firm may have less power to offer on Ibex as it directs supply to the regulated market.

BEH may need to meet its market obligations from more expensive units such as the Maritsa Istok 2 lignite-fired plant, increasing spot prices and potentially leading to higher imports. While the Bulgarian 2020 contract remains at a discount to Hungary, a rare Bulgarian first-quarter 2020 peak-load contract traded in late October at a premium to the Hungarian market.

Greece, traditionally the highest-priced market in the region, has resisted some upside this year as gas burn has become more heavily embedded in the generation mix, in large part as LNG deliveries have stepped up in the second half of this year, and leaving it cheaper than the Romanian market.

Winter outlook: Conclusion

Higher nuclear and renewable generation will limit the need for thermal generation this winter. Highly efficient gas-fired plants remain cheaper to run than mediocre coal-fired ones across Europe, suggesting coal will ramp down first in times of low demand and high renewable generation, for example over the Christmas holiday period.

But coal remains vital to most European grids, in part because grid constraints can require plants in some locations to run despite the wholesale market economics or because they also deliver heat and steam to industrial or household users.

Coal will increasingly act as a peak-load price-setting fuel in continental markets, following the path of the UK and Spain, where coal has been pushed to the peak-load margins.

The market is clearly nervous about the possibility of gas supply disruption in the first quarter of 2020, with both the fourth quarter 2019 and first quarter 2020 spread and the high levels of gas injected into storage as evidence.

But in the event that gas supplies remain stable and current forecasts of a milder, wetter than normal winter in northwest Europe prove to be accurate, gas prices in the first quarter could deliver well below current traded levels and push coal-fired plants even further out of the base-load generation mix. This potentially lifts power prices in the hours where coal-fired generation is called upon — primarily hours 19-21 on weekdays — as plants will have even shorter periods to recoup their fixed costs.

Low gas prices are starting to change the flow of power across European markets. Italy — traditionally the most expensive market in Europe — is now regularly delivering at a discount to markets in southeastern Europe, where gas prices remain oil linked and lignite-fired plants are exposed to high emissions costs.

With more countries using gas to set marginal prices in more hours, the spreads between CWE markets are narrowing as gas-fired plants compete against similar technologies in neighbouring markets, rather than against coal or lignite. This is already apparent in the decline in German exports this year and looks set to continue, encouraging volatile flows throughout the day on many borders.

For more information:

contact@argusmedia.com +44 20 7780 4200 www.argusmedia.com @argusmedia