March 2019

Quarterly Gas Review
Analysis of Prices and Recent Events

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Thanks to Argus Media, we updated our "LNG tightness" metric that measures the spread between the US Gulf Coast LNG FOB and the Henry Hub price. It is interesting to keep track of this 'LNG tightness' in a fast-changing energy world. In December 2018 with Ichthys LNG up and running, Yamal LNG reaching full capacity after train 3 started production a month earlier and the commissioning of Bovanenkovskoye field's third and final gas production facility, an incremental 43 bcm/y capacity increase materialised (or an added 1% of total yearly supply in just a month or a whopping 15% on an annual basis). This at a time when seasonal demand in Asia and Europe didn't pick up due to above normal temperatures while HH prices increased sharply due to a cold spell in the US coupled with low storage levels. This translates into global spare capacity increasing for the first time in the last 3 years, leading to a sharp decrease of our "LNG tightness" indicator. In short, we saw prices picking up in the US where spare capacity doesn't exist while going South in all other regions due to an increase in global spare capacity.

We even achieved, in Q1 2019, Asian LNG spot prices close to European prices, something that happens seldom. But with China imports increasing by 32% in 2018 vs 2017, largely driven by growing LNG imports, this extra spare capacity is going to be reduced sooner rather than later. Nevertheless, with high volatility in our 'LNG tightness indicator', investors are worried about adequate returns and will carefully select the right projects to invest in.

Using Patrick Heather's research[1] we have implemented a methodology to calculate the churn rates of HH for the United States, TTF for North-West Europe and JKM for Asian LNG. For 2018, our analysis shows that JKM, TTF and HH respectively qualify as illiquid, liquid, and very liquid hubs. We will use 2018 as the reference year and will report on the 3 churn rates on a yearly basis to see when JKM becomes liquid.

With the UK on its way out of the EU, the EU Commission re-opened, in December 2018, the idea to "promote the international role of the euro in the field of energy". It is going to be difficult, but essential, for the EU to move to euro denominated commodity trading if it wants to reinforce its economic and energy sovereignty. But thanks to the UK departure, the EU-27 should be in a better position to promote this idea. European Oil Companies such as ENI and Repsol that report and trade in euros could be interested in reducing forex risks. Others like Total and Equinor could be tempted to follow, to mitigate recent unilateral actions by other country jurisdictions. The interesting question would be to see if British BP and Anglo-Dutch Shell decide to follow or stick to their dollar reporting. 20 years after the introduction of the euro, this represents a major new challenge, that could, in the end, allow the EU to enhance protection of its citizens and businesses.

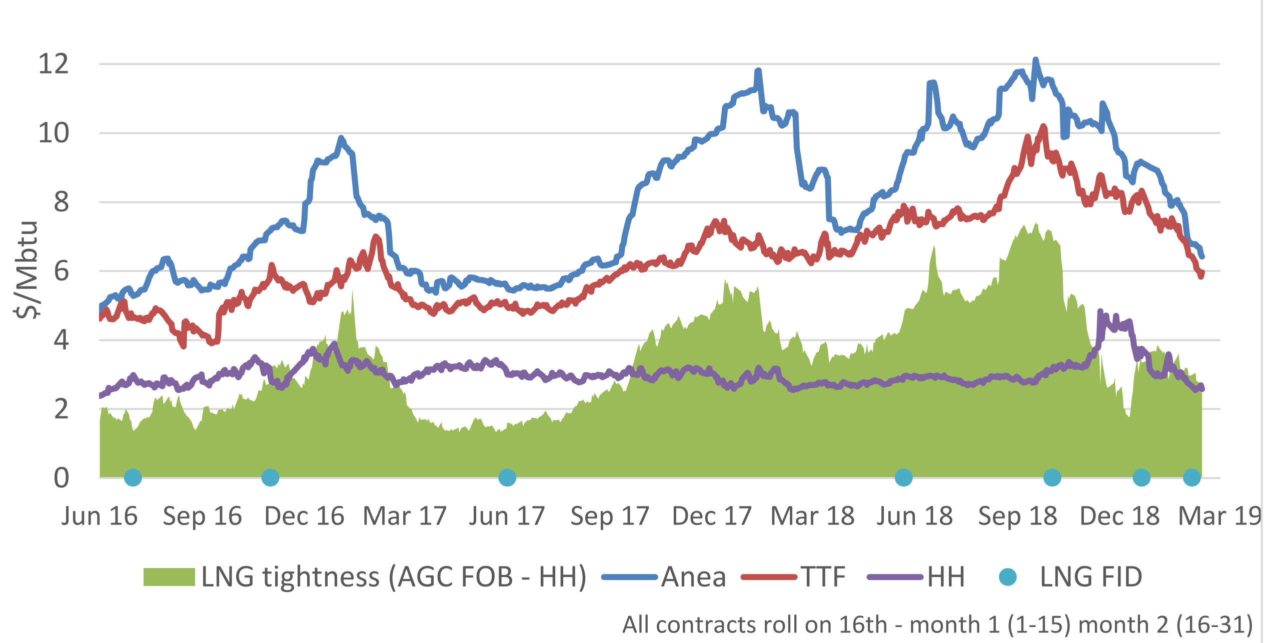
[1] Patrick Heather's research focuses on the 'path to maturity' of traded gas hubs and their stages of development. His latest relevant publication "European traded gas hubs: an updated analysis on liquidity, maturity and barriers to market integration" is available at https://www.oxfordenergy.org/publications/european-traded-gas-hubs-updated-analysis-liquidity-maturity-barriers-market-integration/

Analysis of Prices and Recent Events

Our 'LNG tightness' indicator[2] graph designed with the kind assistance of Argus Media shows:

- TTF Month Ahead (Netherlands) which reflects hub pricing in Europe for both pipeline gas and LNG
- HH Month Ahead (US) which reflects pipeline gas pricing in North America
- ANEA Month Ahead which reflects DES LNG spot pricing in Northeast Asia as assessed by Argus
- The AGC[3] LNG FOB – HH spread, labelled 'LNG tightness': a low spread would suggest a close alignment of worldwide prices (due to higher US prices or increased global competition) while a high spread would suggest that LNG needs to be attracted to demand centres in Asia, Europe, Latin America or the Middle East. A prolonged high spread could also be indicative of the need to invest in new liquefaction capacity. This spread shows the sensitivity of the LNG market
- To better monitor when Final Investment Decisions (FIDs) are taken for LNG projects we also add them.[4]

Figure 1: Worldwide gas prices and LNG tightness



Source: Argus Media, thierrybros.com

On 21 December 2018, BP[5] and partners announced FID for Phase 1 of the Greater Tortue Ahmeyim development. The project will produce gas from an ultra-deepwater subsea system and mid-water floating

[2] T. Bros, March 2018 available at https://www.oxfordenergy.org/publications/quarterly-gas-review-analysis-prices-recent-events/

[3] Since August 2018, Argus has renamed its US Gulf Coast LNG FOB to Argus Gulf Coast LNG FOB (AGC LNG FOB) to better distinguish the Argus physical price assessment from calculated values of Gulf Coast LNG.

[4] For detailed information please refer to Quarterly Gas Review – Issue 2 by T. Bros, June 2018 available at https://www.oxfordenergy.org/publications/quarterly-gas-review-analysis-prices-recent-events-issue-2/

[5] https://www.bp.com/en/global/corporate/news-and-insights/press-releases/bp-announces-final-investment-decision-for-phase-1-of-the-greater-tortue-ahmeyim-lng-development.html

production, storage and offloading (FPSO) vessel, which will process the gas. The gas will then be transferred to a floating liquefied natural gas (FLNG) facility at a nearshore hub located on the Mauritania and Senegal maritime border. The FLNG facility is designed to provide c. 2.5 mtpa of LNG. The project will also make gas available for domestic use in both Mauritania and Senegal. First gas is expected in 2022 but no capex figures have been disclosed[6]. BP Gas Marketing is the sole buyer. This marks the third LNG project FID in 2018 for a total capacity of 21 mtpa, showing that the industry now wants to invest to grow LNG supply post-2022.[7] It is also important to underline that, of the three FID projects, only Cheniere's Corpus extension had existing contracts – for 3 mtpa. BP like Shell are building liquefaction plants to grow their aggregator business model and therefore do not need any contracts to take FID on a new cost-effective project. For the three projects on which FID was taken in 2018, only 14% of the volumes were contracted.

On 5 February 2019, ExxonMobil (30%) and Qatar Petroleum (70%) took FID on the Golden Pass LNG export project located in Texas, that is expected to start up in 2024. Strangely, the press release[8] refers to it as a "$10+ billion investment" for "a capacity of around 16 mtpa" while the September 2018 overview[9] of the project was more precise about the capacity and in line with what is available on the Golden Pass web page,[10] "three liquefaction trains, each approximately 5.2 mtpa". As this rounding could have been done to obscure the price per tonne of the project, we assume that the $10bn+ is $10.5bn, hence the project capex is $0.7bn/mtpa (see figure 9). We expect FID to be taken on another c. 60mtpa in the remaining 10 months of 2019.

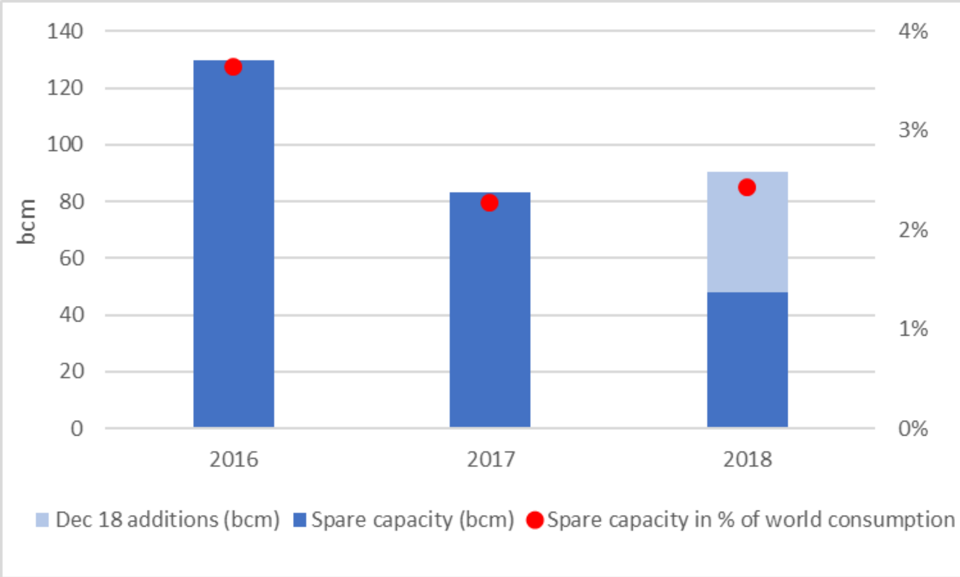
How can our 'LNG tightness' indicator be so volatile?

Figure 1 is a very good illustration of the tightness of the global LNG markets. In December 2018 with Ichthys LNG (8.9 mtpa) up and running[11], Yamal LNG reaching full capacity[12] after train 3 started production a month earlier[13] (5.5 mtpa) and the commissioning of Bovanenkovskoye[14] field's third[15] and final gas production facility, an incremental 43 bcm/y capacity increase materialised (or an added 1% of total yearly supply in just a month or a whopping 15% on an annual basis) at a time when seasonal demand in Asia and Europe did not pick up due to above normal temperatures while HH prices increased sharply due to a cold spell in the US coupled with low storage levels. This translates into the global spare capacity increasing for the first time in the last 3 years, leading to a sharp decrease of our "LNG tightness" indicator to below 2$/Mbtu. In short, we saw prices picking up in the US where spare capacity doesn't exist while going South in all other regions due to an increase in global spare capacity.

It is worth mentioning that even if this increase of production capacity had a bearish impact on LNG prices, this increase is 55% due to pipeline gas. It is not an LNG glut that had this price impact but the combination of both LNG and pipeline capacity growth. The additions in December alone nearly multiply the spare capacity for FY 2018 by 2 (from 48 to 91 bcm).

[6] "The parties will continue to finalise agreements and obtain final regulatory and contract approvals, following which Phase 1 will move into a detailed design and construction phase, with award of engineering, procurement, construction and installation (EPCI) contracts. Project execution activities are expected to commence in 1Q 2019." Hopefully some capex numbers will be provided then.
[7] For more information please refer to the spare capacity calculations provided in T. Bros, Quarterly Gas review – Issue 3, September 2018 available at https://www.oxfordenergy.org/publications/quarterly-gas-review-issue-3/
[8] https://corporate.exxonmobil.com/News/Newsroom/News-releases/2019/0205_ExxonMobil-Qatar-Petroleum-to-Proceed-with-Golden-Pass-LNG-Export-Project
[9] https://corporate.exxonmobil.com/Energy-and-environment/Energy-resources/Natural-gas/Liquefied-natural-gas/Plans-to-expand-the-Golden-Pass-terminal-could-generate-up-to-45000-jobs-nationwide#benefitsToTheLocalEconomy
[10] http://www.goldenpassproducts.com/index.cfm/newsroom/detail/99
[11] http://www.inpex.com.au/news-media/news/inpex-confirms-first-lng-cargo-from-ichthys-lng-project/
[12] http://www.novatek.ru/en/press/releases/index.php?id_4=2869
[13] http://www.novatek.ru/en/press/releases/index.php?id_4=2828
[14] http://www.gazprom.com/press/news/2018/december/article469885/
[15] Designed production capacity: 115 bcm/y with three upstream facilities. Two of them have been already brought online: the first one, in 2012 (60 bcm/y), the second one, in 2014 (30 bcm/y). This leaves 25 bcm/y (Russian standards) or 23 bcm/y under EU standards for the third.

Figure 2: Spare capacity 2016-2018



Source: thierrybros.com

It is also important to underline that if the consequence of an increase in spare capacity is to reduce prices, it is more in the interest of consumers than producers to make sure that new projects are put online ahead of demand growth and not vice-versa. This is totally in line with a 2018 KAPSARC study[16] which found that OPEC's spare capacity reduces oil price volatility and generates between $170 and $200bn of annual economic benefits for the global economy. A 'wait-and-see' attitude from the consumer side is the perfect recipe for a boom and bust commodity! This is why a timely analysis of gas investment is needed to be able to forecast additional supply in front of expected demand growth. In a post-COP 21 world, it is not acceptable to treat oil and gas together. In its World Energy Investment 2018 published in July 2018, the IEA provides an overall analysis, but as the organisation still bundles 'oil & gas supply' this does not help to forecast either the oil or gas spare capacity. The author believes it is high time for the IEA to decouple gas from oil, as it already does for coal supply. It would also be useful if all oil & gas companies could also provide a split of their capex between oil and gas projects.

Then in Q1 19, the US market rebalanced itself providing *de facto* added flexibility to the global market. This relaxed market, even managed to push Asian spot prices close to European prices, something that is seldom seen with our 'LNG tightness' closing at 2.5$/Mbtu. But with China imports increasing by 32% in 2018 vs 2017[17] (125 bcm), largely driven by growing LNG imports, this extra spare capacity will be reduced sooner rather than later. Nevertheless, with high volatility in our 'LNG tightness indicator', investors are worried about adequate returns and will carefully select the right projects for FID. The excessively high capex witnessed in Australia is not acceptable any longer. But resilient oil prices and a lower cost environment should be favourable to the launch of new projects.

In December 2018, China and the US agreed to resume trade negotiations and temporarily halt further tariff hikes, which could help restore trade flows for US LNG that have been facing a 10% retaliatory tariff from China since September 2018. As China is the fastest growing LNG market and should soon become the largest LNG importer, the outcome of those negotiations could favour country specific liquefaction FIDs in 2019.

[16] 'OPEC's Impact on Oil Price Volatility: The Role of Spare Capacity' in the Energy Journal, Vol. 39, No. 2, 2018
[17] https://www.naturalgasworld.com/chinas-2018-gas-imports-up-32-67262

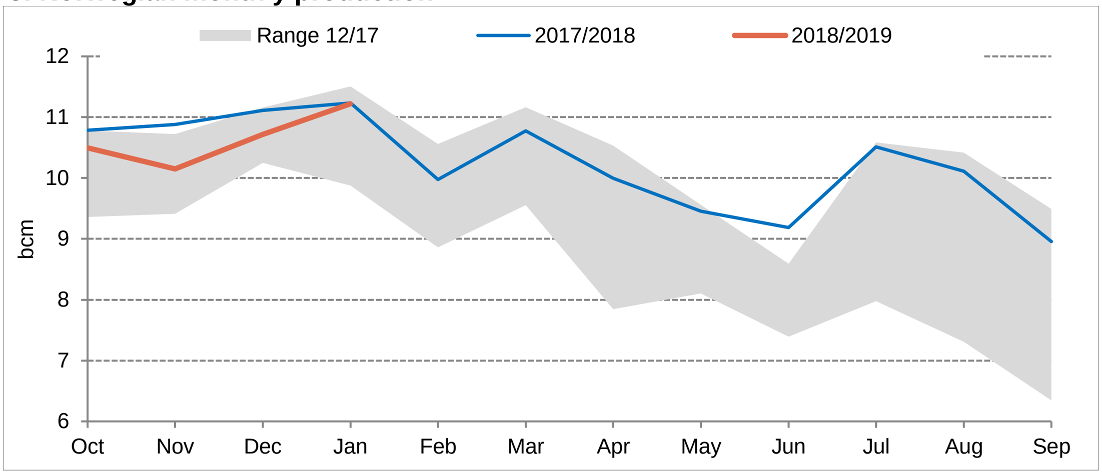
European LNG and pipeline gas movements

As Yamal production has been so much ahead of schedule, the project is short of Arc7 ice-class LNG tankers, and had to find a way of avoiding delivering LNG all the way to western European ports, which would cut sailing distances, in particular in winter when the Northern Route is closed to navigation. This was implemented, in the 2018/19 winter, thanks to a new Norwegian trans-shipment terminal able to host ship-to-ship operations for the whole Yamal capacity, freeing up ice breakers sooner.

With this extra baseload LNG, regas terminals in North West Europe operated at record level in December, displacing pipeline gas and reducing the need for some storage withdrawal with EU-27 still 42% full at end February vs 29% last year(see figure 6).

On one hand, after reaching a record level in 2017, Norwegian gas production went down in 2018 (-2.1%) and was even lower, for the first time since 2012, than the official forecast.[18] This was due to technical problems on some fields. Could this be repeated in 2019 with a FY forecast of 121.7 bcm (2.2% less than the 2018 forecast)?

Figure 3: Norwegian monthly production

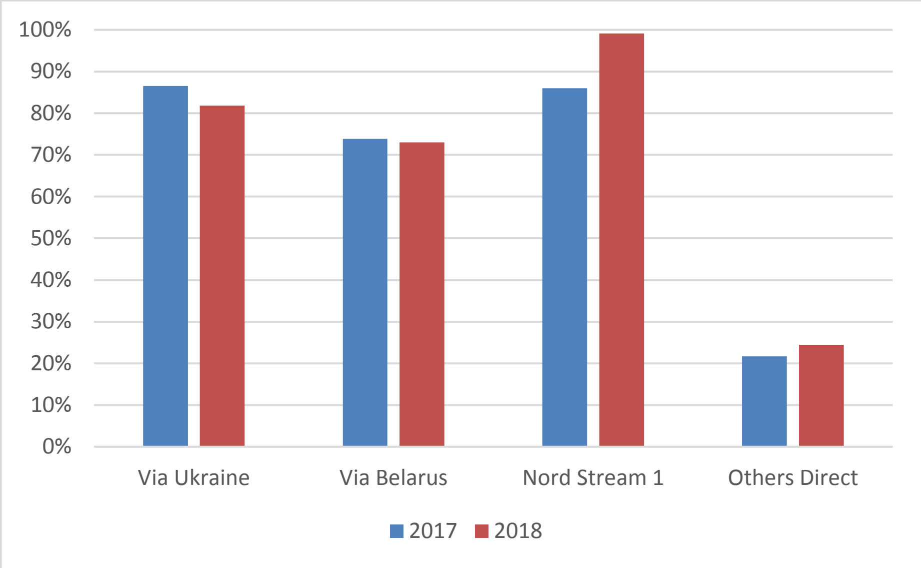


Source: NPD, thierrybros.com

On the other hand, Gazprom's flows to Europe in 2018 reached an all-time high of 168 bcm (or +2% vs 2017). An interesting point about 2018 is that Gazprom's exports to Europe were higher in summer (84.7 bcm in Q2 & Q3) than in winter (83.5 bcm in Q1 & Q4). This can be explained by the need to replenish depleted stocks in Q2 at a time when LNG was moving to Asia, while LNG came to Europe in Q4 18. This is a testimony of Gazprom's flexibility, which allows it now to fine tune its supplies to EU customers by selling gas not only via long term contracts but also via auctions or via its European subsidiaries. This allows Europe to access the cheapest available gas (ie Russian pipeline gas in Q2 and LNG in Q4): working markets are for the benefit of consumers.

[18] -2.2% vs the Norwegian Petroleum Directorate FY forecast made in January 2018. Data available at http://www.npd.no/en/news/production-figures/

Figure 4: Annual load factor of Gazprom Routes for Western Exports



Source: Gazprom, Nord Stream 1, Entsog, thierrybros.com

This very clearly shows that Gazprom, for economic purposes, is maximising the use of its own Nord Stream 1 pipeline (on baseload) at the expense of Ukrainian transit (flexible). But with Nord Stream 1 now fully used, Gazprom cannot increase its direct flows through this pipe further in 2019. This means that the spread of exports across routes in 2019 should look similar to 2018 except for Ukraine, which provides the flexibility. If Gazprom exports even more volumes in 2019 vs 2018, Ukraine flows, load factor and revenues will increase but if Gazprom exports less, Ukraine flows, load factor and revenues will continue to decrease.

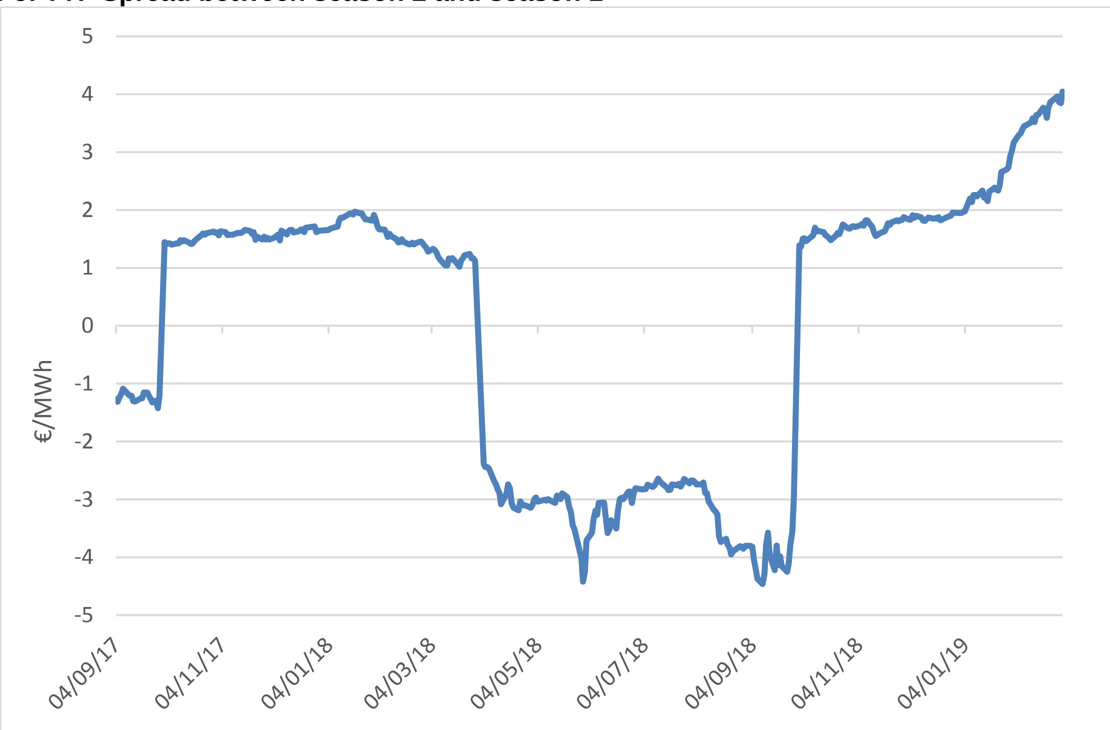
The major unknown is now the future of the Ukrainian transit contract, which expires on 31 December 2019. On 21 January, a trilateral meeting between EU, Russia and Ukrainian ministers was held in Brussels[19] on the future of gas transit via Ukraine post 2020, with the next ministerial meeting scheduled in May. The EU proposals (duration, volumes and tariffs) have not been made public, but we re-iterate that the only economic option could be for Ukraine to offer "a fixed €1bn/year[20] deal to transit any quantities up to 100 bcm/y" as explained in the last quarterly review[21]. According to Naftogaz, "the new gas transit contract should be long-term, i.e. 10 or more years, and provide for transit volumes that would be economically viable for a high-profile European investor".[22] Hence what is new is the 10-year duration, but Gazprom could be willing to avoid such a long commitment. Perhaps the likely outcome could look like a 10-year contract for up to 100 bcm/y, and a fixed €1bn/year, with a revision in 5 years' time. But with Gazprom more focussed on Nord Stream 2 construction than the transit negotiations and EU Vice-President for Energy Union Maroš Šefčovič on leave for campaigning at the Slovak presidential elections since 1 February, the probability of a transit deal being signed in 2019 has further decreased, making the need for storage refilling and LNG loadings even more important in the months to come.

[19] http://europa.eu/rapid/press-release_STATEMENT-19-562_en.htm
[20] It would also make much more sense to avoid using $ in such a deal. The €0.3bn difference is to cover the cost of the extra transport from the Ukrainian border to the main demand centres in the EU.
[21] T. Bros, November 2018 available at https://www.oxfordenergy.org/publications/quarterly-gas-review-issue-4/
[22] http://naftogaz.com/www/3/nakweben.nsf/0/48F5648BC10B833CC2258389007235D5?OpenDocument&year=2019&month=01&nt=News&

What is Q4 18 telling us about Q4 19?

We ended 2018 with record underground gas storage[23] levels in Europe - something that could prefigure a repetition for what we could witness next year if an Ukrainian transit deal can only be reached at the last minute on 31 December 2019 (or even later, in 2020).[24] The actual increase in the TTF winter-summer 2019 spread is a very good indication that our analysis will turn out right, as it incentivises traders to store gas this summer for withdrawal during next winter.

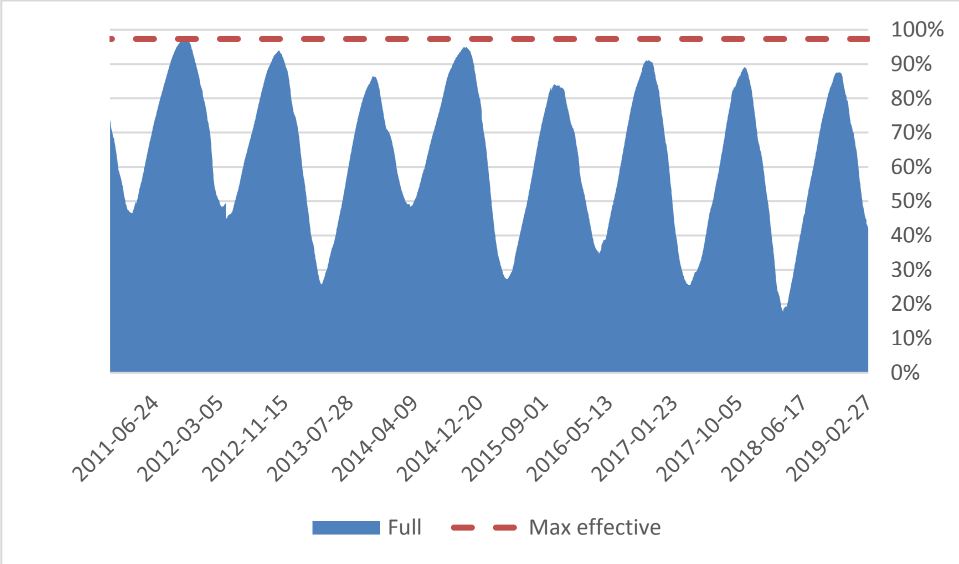
Figure 5: TTF Spread between season 2 and season 1



Source: Argus Media, thierrybros.com

[23] We took no account of LNG tank capacity. According to the Gas Infrastructure Europe (GIE) transparency platform (https://agsi.gie.eu/#/), EU-27 storage capacity is now 1,060 TWh.
[24] T. Bros, November 2018 available at https://www.oxfordenergy.org/publications/quarterly-gas-review-issue-4/

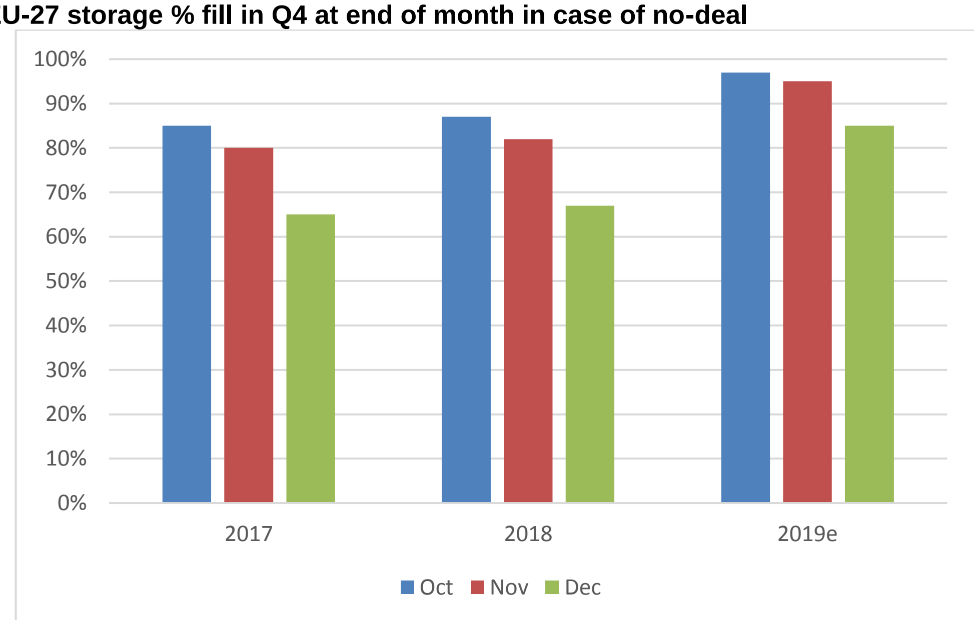
Figure 6: EU-27 underground gas storage use



Source: GIE, thierrybros.com

With storage still relatively full compared with its five-year average, cheap summer prices and no-reload incentives, it is likely that storage could be refilled to its record level ahead of next winter. In our last quarterly review, our conclusion was that "if no-deal is reached before the beginning of 2020, storage withdrawals will be reduced in November-December 2019 to mitigate this transit risk. This could result in 15 bcm more gas in stock at end December 2019 vs 2018." Higher end-2018 storage levels validate our conclusion that the need for a contract to be signed between Gazprom and Naftogaz Transport could be delayed up to April 2020 as storage and LNG could make up any shortfall until then.

Figure 7: EU-27 storage % fill in Q4 at end of month in case of no-deal

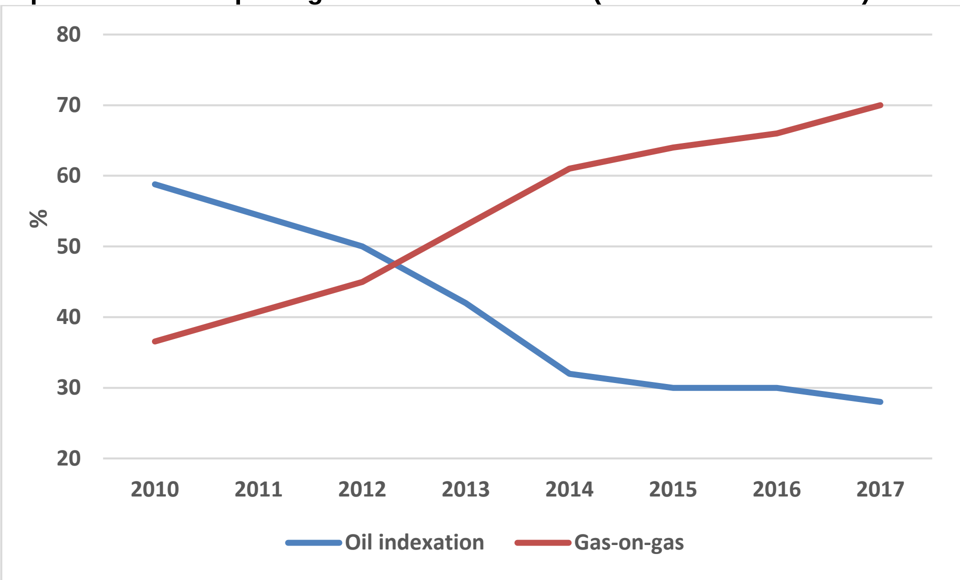


Source: GIE for historical data, thierrybros.com

A new global churn ratio analysis

In December 2018, Tellurian entered into a Memorandum of Understanding with Vitol to supply 1.5 mtpa of LNG with a transaction price based on the Platts Japan Korea Marker (JKM) and is for a minimum term of 15 years[25]. This marks the first LNG contract using JKM, that is going through exponential growth. As JKM could become an international benchmark, we decided to investigate the Asian churn ratio vs the 2 other more liquid hubs to find out when trading a majority of the LNG ships under a liquid index could become reality. Also it is highly likely that we could see in the Asian LNG market what we witnessed in Europe for gas. In 2013, we moved from gas being mostly oil-indexed to being sold on hubs. This was a tipping point after which European utilities that had resisted this move for years had, overnight, to painfully adapt to a new business model and the laggards were hit the hardest.

Figure 8: European wholesale pricing evolution 2010-2017 (in % of total demand)



Source: IGU, thierrybros.com

With Patrick Heather[26] we decided to calculate the 3 churn rates taking into account all trades (Exchange & OTC): HH for the United States, TTF for North-West Europe and JKM for Asian LNG and by dividing them by the relevant physical volumes:

- For HH, we took into account the US production and net pipeline imports;
- For TTF, we took the demand in France, Benelux, Germany, Austria and the Czech Republic;
- For JKM, we accounted for the LNG delivered into 4 specific countries - Japan, South Korea, China and Taiwan, which together import 61%[27] of the total worldwide LNG supply.

For the data to be homogeneous, all physical volumes are taken from JODI[28] and the conversion factors are those disclosed by the BP Statistical Review.

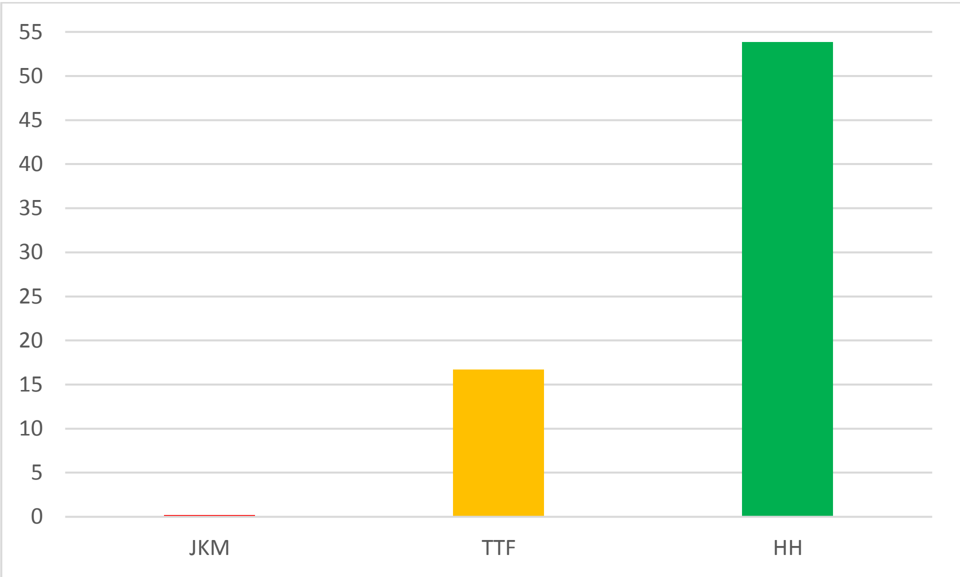
[25] https://content.equisolve.net/tellurianinc/news/2018-12-06_Tellurian_and_Vitol_Sign_MOU_for_15_year_LNG_sale__205.pdf
[26] Patrick Heather's research focuses on the 'path to maturity' of traded gas hubs and their stages of development. His latest relevant publication "European traded gas hubs: an updated analysis on liquidity, maturity and barriers to market integration" is available at https://www.oxfordenergy.org/publications/european-traded-gas-hubs-updated-analysis-liquidity-maturity-barriers-market-integration/
[27] GIIGNL data for 2017
[28] http://www.jodidb.org/ReportFolders/reportFolders.aspx. Except for LNG imports into China and Taiwan not disclosed by JODI, we used trade press information.

The volumes of trade in JKM swaps in 2018 reached a record high of 179,795 lots (of 10,000 Mbtu or a total of 38.7 mt or 52.7 bcm), according to data from ICE and CME[29]. Volumes were over three times higher than the 50,236 lots traded in 2017. With a total of 38.7 mt of LNG cleared using this benchmark price assessment for spot physical cargoes delivered ex-ship into Japan, China, South Korea and Taiwan for a total LNG intake of 195 mt in 2018, the 2018 JKM churn ratio was therefore 0.2.

London Energy Brokers' Association[30] reported that the total TTF Over The Counter (OTC) volumes for 2018 stood at 21,250 TWh. Another, 12,389 TWh were traded using ICE (11,564 TWh futures. 818 TWh options and 7 TWh spot). Finally 1,068 TWh were traded using Pegas[31] (686 TWh futures and 382 TWh spot). From this we calculated the total volumes traded under TTF in 2018 to be 34,707 TWh. If we take here the relevant market as being the demand in France, Benelux, Germany, Austria and the Czech Republic we have a total of 207.5 bcm in 2018. Therefore the churn ratio for TTF was 16.7 in 2018.

According to CME the total volume traded in 2018 under HH at Nymex/CME for both HH and Nat Gas contracts was 158,009,439 lots (114,256,078 lots NG futures, 4,579,077 lots HH futures and 39,174,284 lots NG options), ie 463,080 TWh. In 2018, US production was 851 bcm and net pipeline imports 8 bcm, equivalent to total of 8,596 TWh. This provides us with a HH churn rate of 53.9. This is such a liquid market that there is little OTC HH trading.

Figure 9: 2018 churn rate



Source: Patrick Heather, thierrybros.com

Adapting Patrick Heather's European methodology to the world, we end up with JKM, TTF and HH qualifying respectively as illiquid, liquid, and very liquid hubs[32]. We will use 2018 as the reference year and will report on a yearly basis on the 3 churn rates to see when JKM becomes liquid, as we believe it will thanks to the EU-Japan Memorandum of Cooperation[33] on promoting and establishing a liquid, flexible and transparent global LNG market; this could be around 2022e. As stated in our last quarterly review, the Shell LNG Canada FID taken without any long-term contracts could be explained by the emergence of an Asian index (this plant on the West coast of Canada will serve only Asian customers) allowing Shell to then use this liquid index

[29] Platts LNG Daily, 14 January 2019
[30] https://cdn.evia.org.uk/content/monthly_vol_reports/LEBA%20Energy%20Volume%20Report%20December%202018.pdf
[31] https://www.powernext.com/press-release/pegas-trading-volumes-2018
[32] We defined illiquid, liquid and very liquid churn rates as respectively, below 15, between 15 and 50 and above 50. It is also important to mention that in the US other hubs also trade, although mainly in lower volumes and mostly on spreads vs HH.
[33] https://ec.europa.eu/energy/en/news/eu-and-japan-boost-cooperation-energy-security

once production starts around 2025. Also, we must keep in mind that TTF only became the most liquid European hub from 2016[34]. So even if the global ranking order looks set in stone for the coming years, as LNG supply is growing faster than gas demand in France, Benelux, Germany, Austria and the Czech Republic, we could see JKM liquidity overtaking TTF by 2030.

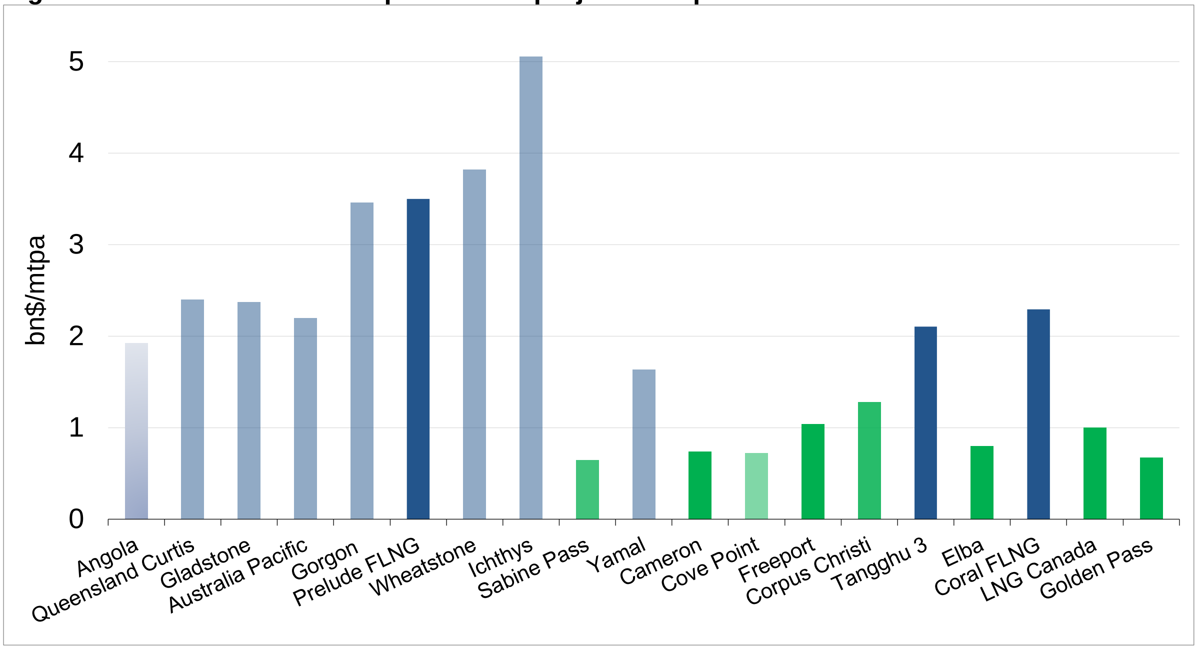
LNG is now versatile but needs to become low cost

LNG supply is very versatile because of floating regas and liquefaction. Customers can plug in and out units to balance unexpected swings, as we are seeing in Argentina which is moving in 2019 from an importing to an importing and exporting country. A more geopolitical use of FSRU is the commissioning of a unit in January 2019 at Kaliningrad, the Russian exclave, making Russia both an LNG exporter (Sakhalin and Yamal) and an importer (this is the only FSRU in Russia). The FSRU has been named after Marshal Aleksander Vasilevskiy, who was responsible for planning and coordinating almost all decisive Soviet offensives in World War II. Using his name for an FSRU berthed between Poland, Lithuania and Denmark can be seen as a sign of strained Russian-EU relations, but it is also interesting that Gazprom's press release[35] says: "The Kaliningrad Region has been provided with a totally independent gas supply route. Gazprom has brought the region's energy security to a fundamentally new level." This shows very clearly that LNG cuts out all transit risks and gives. Kaliningrad full energy independence from its European neighbours.

In December 2018, Total mentioned[36] that its Australian Ichthys project has seen its capex balloon from an initial $34bn to a final $45bn (+32%), making this project the most expensive worldwide on an LNG capacity basis. If we wish to compare projects (in Figure 9) using only the total disclosed capex per unit of production we have to consider that the North American model is unbundled (i.e. upstream and pipeline transport are not integrated in the LNG projects, in green below) whereas the rest of the world (in blue below) remains bundled. Projects are listed according to the timing of the FID with shaded ones for those already in (full or partial) production. Projects such as the recent BP Greater Tortue Ahmeyim development which have not disclosed capex are not listed on this graph as it is impossible to provide a fair measurement of their economics.

[34] See Patrick Heather's "European traded gas hubs: an updated analysis on liquidity, maturity and barriers to market integration" available at https://www.oxfordenergy.org/publications/european-traded-gas-hubs-updated-analysis-liquidity-maturity-barriers-market-integration/
[35] http://www.gazprom.com/press/news/2019/january/article472626/
[36] https://www.naturalgasworld.com/ichthys-cost-balloons-66720

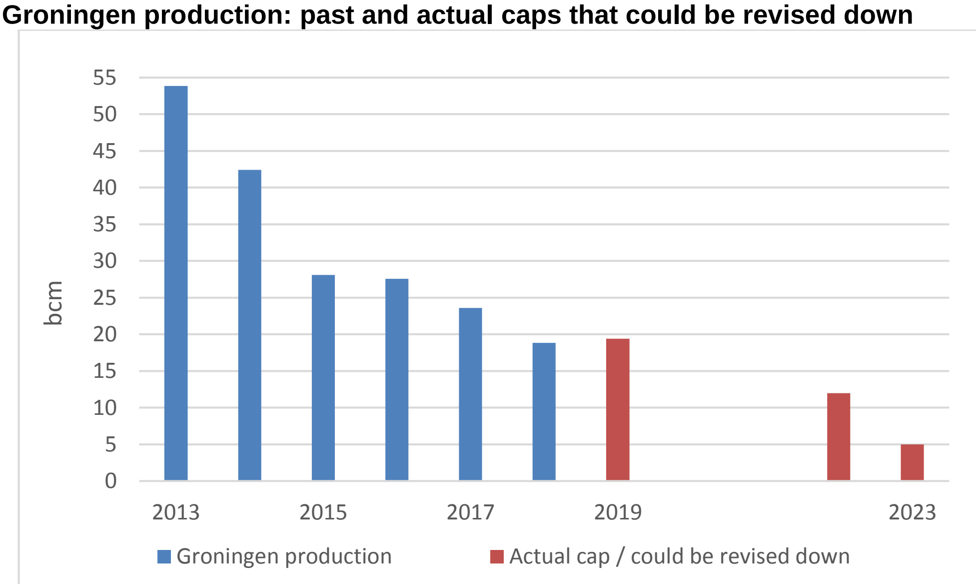
Figure 10: Latest disclosed capex of LNG projects in operation and in construction



Source: thierrybros.com, company data

The Dutch government confirmed on 3 December 2018 its plan to continue to cut production from Groningen by imposing a new 5 bcm/year cap by 2023, a significant cut from the 2018 production (18.8 bcm). As Figure 10 shows, the 2019 target is very similar to 2018's and would need to be revised down to please Dutch voters who want a quick total gas phase-out. And with Groningen producing on a baseload basis and therefore providing little swing any longer, winter demand would need to be meet by high imports and storage withdrawals. Last year the Netherlands became a net gas importer for the first time and this trend will continue, as the government orders permanent and steeper cuts at Groningen.

Figure 11: Groningen production: past and actual caps that could be revised down



Source: NAM for historical data, thierrybros.com

An interesting poll would be to ask the Dutch how they would have liked the historical gas rent to be managed. The Netherlands, like the UK, decided from the start to direct the revenues to the day-to-day state budget, while Norway decided to put the rent into a sovereign fund for future generations. In fact, by not implementing a sovereign fund, the Dutch state only provided rent to the 1965-2015 generation that benefited from Groningen production. And now the Dutch have to live with the consequences of the closure of Groningen (tremors) without any income (closing Groningen means no taxes collected either at the production level or at the corporate level). It is uncertain if today's young generation is very happy about this. This shows that not only rent maximization is important but, in a world moving away from oil, the inter-generation split of the actual rent will become an issue. The Netherlands was well known in economics books for having invented not only the theory of long-term oil-indexed gas contracts but also the Dutch disease (an economic term that refers to the negative consequences arising from large increases in the value of a country's currency due to natural resource production). It could now be surveyed to see how a rich oil & gas producer can cope in an energy transition world. Could the Dutch economy, that was praised in Europe pre-2015 for sound budgeting thanks to the Groningen revenue, soon resemble more the ones in Southern Europe (France, Greece, Italy, Portugal or Spain)? If this is the case, then the overall balance in the eurozone between South and North economies could be tilted in favor of running more deficits. The inter-generation split over the climate change bill is also partially behind the "Gilets Jaunes" in France.

The older generations have benefitted from the coal and oil economic revolutions to boost their purchasing power, leaving the younger generations to deal with the cost of climate change; this could generate tensions in democratic states on who is responsible and who should pay. The energy transition that we must achieve will now have to take this economic dimension into account. It is not possible anywhere else then in Germany to assume that all residential customers can afford to see their electricity bill going up[37]. Policymakers will need to find an economically acceptable energy transition. At a time when renewable energy is still intermittent, the gas industry with its storage buffers should make sure it can provide on-demand energy at relatively low cost not only to stay competitive but to keep its social license.

[37] In Germany residential electricity bill went up to pay for the cost of moving from nuclear to renewable, without any material impact on the German CO2 emissions.

Brexit update

In January the UK National Audit Office published "Oil and gas in the UK – offshore decommissioning", a report[38] showing that the government received £334bn of net tax revenues from the oil and gas sector between 1970-71 and 2016-17, with peak revenue in 1984-85 of £30bn or 11% of government receipts. Nevertheless, in 2016-17, the government paid out more to oil and gas operators in tax reliefs than it received in revenues, resulting in total repayments of £0.3bn. With operators decommissioning their assets as they reach the end of their useful economic lives, "HM Revenue & Customs estimates that tax repayments and forgone taxes associated with decommissioning will cost the government £24bn, but this is subject to significant uncertainty. Taxpayers are ultimately liable for the total cost of decommissioning assets that operators cannot decommission." As in the Netherlands, with production declining and more decommissioning, intergeneration solidarity could soon become an issue in the UK, with the baby boomers having enjoyed the oil and gas jobs and revenues and the generations to come having to foot the bill for the decommissioning and climate change.

Brexit provides opportunities to the EU . . .

With the UK on its way out, in December 2018 the EU Commission revived the idea of promoting "the international role of the euro in the field of energy".[39] "Recent global trends are supporting a potential shift towards a more diversified and multipolar system of several global currencies. The decision to use a currency is ultimately made by market participants. The objective is not to interfere in commercial freedom or limit choice, but rather to expand the choice for market participants by ensuring that the euro represents a strong and reliable currency of choice."[40] It is going to be difficult but essential for the EU to move to euro denominated commodity trading if it wants "to reinforce its economic and energy sovereignty".[41] But thanks to the UK departure, the EU-27 should be in a better position to promote this idea. The major traded platforms ICE and NYMEX are not based in the EU-27 and if the EU pushes for intergovernmental agreements "to include a model clause related to the use of euro as a default currency for energy transactions"[42] they will either have to adapt or a new competitor inside EU-27 could emerge. The Commission also thinks that "Central Stockholding Entities and obligated economic operators under the Oil Stocks Directive could be among the early adopters of such a euro-based contract."[43] European Oil Companies like ENI and Repsol that report and trade in euros could be interested in reducing forex risks. Others like Total and Equinor could be tempted to follow, to mitigate "recent unilateral actions by third country jurisdictions, together with declining support for international rules based governance and trade can impede or at least make energy trade more difficult".[44] The interesting question would be to see if British BP and Anglo-Dutch Shell decide to follow or stick to their dollar reporting. 20 years after the introduction of the euro, this represents a major new challenge, that could in the end "allow the EU to enhance protection of its citizens and businesses".[45] A conference[46] on the international role of the euro in the field of energy was organised on 14 February with a plan to report on the results in the summer,

While Brexit is in full swing on one side, EU integration is improving on the other side. The EU willingness to reduce its transportation costs by implementing the Quo Vadis[47] idea is moving forward with Transmission

[38] Free summary available at https://www.nao.org.uk/wp-content/uploads/2019/01/Oil-and-gas-in-the-UK-offshore-decommissioning-Summary.pdf
[39] https://ec.europa.eu/commission/publications/towards-stronger-international-role-euro-commission-contribution-european-council-13-14-december-2018_en
[40] Page 2 https://ec.europa.eu/commission/sites/beta-political/files/factsheet-strengthen-euro-global-role-05122018_en.pdf
[41] Page 6 of the Commission paper
[42] Page 6 of the Commission paper
[43] Page 7 of the Commission paper
[44] Pages 1 and 2 of the Commission paper
[45] Page 5 of the Commission paper
[46] https://ec.europa.eu/info/events/international-role-euro-field-energy-2019-feb-14_en
[47] The "Quo Vadis EU gas regulatory framework" study was carried out to analyse whether the current regulatory framework in the EU gas sector is efficient in order to maximise overall EU welfare or whether changes may be necessary, and if so provide recommendations. More info on https://ec.europa.eu/energy/en/studies/study-quo-vadis-gas-market-regulatory-framework

system operators (TSO) in Finland, Latvia and Estonia signing [48] in February 2019 an Inter TSO Compensation agreement, which enables the functioning of a single gas transmission tariff zone from 2020. This merger should not only reduce costs but increase security of supply in an area highly dependent on Gazprom by providing diversification of supply and shared storage.

… and unexpected challenges to come

The last decade, with the examples of E.On and RWE losing time and money in unsuccessfully trying to fight policies implemented by democratically elected governments, showed that resisting energy policy is futile. Hence contrary to Eurogas[49] and Eurelectric[50] identified "areas of concern that will need to be addressed in a future relationship to minimise disruption to gas markets", Energy companies should adapt to the energy revolutions, focus on customers, put into action the EU targets, reduce CO_2 emissions to fight climate change, and not interfere in this very difficult divorce. The situation mentioned in our latest Brexit comment[51] confirms our views[52] that Eurogas and Eurelectric had identified the 'wrong' "areas of concern that will need to be addressed in a future relationship to minimise disruption to gas markets"; the issues they had addressed were wrong both on the political and day-to-day levels[53]. It is interesting also to note that Eurogas called for "reflection on security of supply in the context of the Gas Directive"[54] a few days before Member States "gave a mandate to the Presidency of the Council to start negotiations with the European Parliament on an amendment to the Gas Directive. The proposed amendment aims to extend the application of the EU's gas market rules to pipelines to and from outside countries."[55] It is now likely that the Directive that managed to get a provisional political agreement between the Council and the Parliament could be adopted before the next European elections, in May 2019, negatively impacting Nord Stream 2. In short, to stay competitive in a fast-changing environment, gas companies should focus only on their business and not interfere with policymaking. In democratic states, policy is designed for the benefit of the majority (ie customers) and so companies will lose time and money in fighting changes, when they could instead benefit from them if they are the first movers.

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[48] https://www.elering.ee/en/gas-tsos-finland-estonia-and-latvia-have-reached-new-voluntary-agreement-inter-tso-compensation

[49] https://eurogas.org/website/wp-content/uploads/2018/10/Letter-to-Mr-Barnier.pdf

[50] https://cdn.eurelectric.org/media/3416/brexit_letter_-_15_october-2018-2650-0008-01-e-h-F868B7FF.pdf The Eurelectric's letter was strangely addressed to Prime Minister May and Chief Negotiator Barnier in the text but had only one recipient: M. Barnier!

[51] T. Bros, November 2018 available at https://www.oxfordenergy.org/publications/quarterly-gas-review-issue-4/

[52] For detailed information please refer to Quarterly Gas Review, Issue 4 by T. Bros, November 2018 available at: https://www.oxfordenergy.org/publications/quarterly-gas-review-issue-4/

[53] An improved letter dated 12 November 2018 signed by UK Energy, EFET, Entose, Entsog, Eurelectric, Eurogas, Scottish Renewables, Solar Power Europe and Wind Europe on a similar subject was both addressed to M. Barnier and then UK Secretary of State, Department for Exiting the EU Raab available at http://www.solarpowereurope.org/wp-content/uploads/2018/11/Letter-in-support-of-energy-and-climate-in-the-Political-declaration-2.pdf

[54] 18 January press release available at https://eurogas.org/website/wp-content/uploads/2019/01/01.18.-Statement_Eurogas-calls-for-reflection-on-SoS-in-the-context-of-the-Gas-Directive.pdf

[55] "Gas directive: Council agrees negotiating mandate" press release available https://www.consilium.europa.eu/en/press/press-releases/2019/02/08/gas-directive-council-agrees-negotiating-mandate/