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Turkey, Russia agree on go-ahead for Turkish Stream

Anadolu Agency, *01.09.2016*

For Turkey and Russia agreed to accelerate the Turkish Stream process and to take the necessary steps to resolve the arbitration issue on pricing of Russian gas imports to Turkey as soon as possible, statements from Turkey's energy ministry headed by Berat Albayrak and Russia's Gazprom revealed late.

Turkey's Energy and Natural Resources Minister Berat Albayrak held talks to discuss and evaluate energy cooperation between Turkey and Russia with a delegation from Gazprom headed by the company's Chief Executive Officer (CEO) Alexey Miller in Istanbul.

After Albayrak's one-on-one meeting with Miller, Turkish energy officials in a separate meeting with the Gazprom delegation discussed the Turkish Stream project, the arbitration case to apply discount on Russian gas exports as well as other topics of regional energy cooperation.

"We will take positive steps in the area of energy in the short term with Russia. We always prioritize our hope to bring this cooperation to a higher level," Albayrak said after his meeting with Miller.
Both sides published statements after the meetings. "During the meeting, the parties agreed to finalize, in the shortest time, the granting of all necessary permits to start the implementation of the Turkish Stream project," both the ministry and Gazprom said in the statements.

The Turkish Stream pipeline project, which was announced by Russian President Vladimir Putin in December 2014 during his visit to Ankara, plans to carry Russian gas via the Black Sea and Turkey to South Eastern Europe. Originally planned as a four-way pipeline with an annual transfer capacity of 63 billion cubic meters (bcm), the project was later reduced to a two-way pipeline, with a capacity of 32 bcm. Additionally, the parties expressed their determination to solve the arbitration court case between the two countries.

A lack of progress in the project was put down to Russia's non application of the 10.25 percent gas price discount to Turkey's gas contract with Russia which was previously agreed on. Then, Turkey decided to take Russia to the international arbitration court in October 2015. "The commercial negotiations on the terms of Russian natural gas supply to Turkey will continue. The parties also discussed the main issues related to regional energy cooperation," Gazprom's statement revealed.

Turkey's LNG role in Eastern Europe is critical

ICIS, *01.09.2016*

Although the imminent expiry of two Gazprom contracts and the release of capacity on certain sections of the Western Line will not affect Turkey directly, the country's role should not be underestimated since it has the potential to transform the region within the next five years.

The pipeline has been transporting natural gas from Russia to Turkey and Greece via Ukraine, the Republic of Moldova, Romania and Bulgaria for three decades. However, with the expiry of two contracts at Romania's interconnection points with Ukraine and Bulgaria, capacity will be freed up to third parties, bringing much-needed competition to the region.

Of equal importance is the fact that capacity on the Bulgarian-Greek border has also become available earlier this summer thanks to the latest changes to the EU's network codes, which include requirements to harmonise the allocation of capacity in pipelines as well as streamline gas trading, gas transmission and data exchange. This, in effect, will help to establish a bidirectional north-south corridor linking Ukraine to Greece and pave the way for the launch of a gas market.

The four countries have already signed interconnection agreements, and Romania will hold its first capacity auctions on its border with Bulgaria on 5 September. Despite the great opportunities that these changes usher in, their success relies on securing gas volumes.

In this context it is important to stress that the most obvious source of supply would still be Russia's Gazprom. Even so, the changes that come will give the region's private companies the opportunity to source their gas from Russia and sell it independently of Gazprom. Nevertheless, any contracts that would be signed in EU member states would have to be compliant with EU anti-trust rules, testing Gazprom's behaviour in eastern Europe, as a former diplomat put it in an interview with ICIS.

New sources of natural gas that arrive in the region from the Caspian and the Black Sea by the end of the decade should introduce an element of competition, but the period between now and 2020 will be critical. It is here that Turkey's role cannot be underestimated.

Gazprom has signed a number of supply agreements with Turkey's private importers and the incumbent BOTAS, which amount to a contractual annual volume of 14 billion cubic metres (bcm). The volumes are delivered on the Western Line. Five supply contracts with BOTAS and four private importers will expire in 2021. The remaining four contracts will be phased out between 2036 and 2043.

This means that Turkey’s interconnection with Bulgaria on the Western Line will not be available for third-party access until at least 2021. Nevertheless, Turkey could fast-track the construction of its interconnector with Bulgaria and establish reverse flows with its western neighbour. The link is in fact considered a project of common interest (PCI) by Brussels and Turkey could benefit from EU funding as a result. On the other hand, Turkey could boost the existing interconnection capacity with Greece and establish reverse flows on the border.

Although Turkey has experienced gas supply constraints in its high-consumption northwestern Marmara region in recent years, its plan to expand its LNG capacity would be of great importance both for its own market as well as that of the region. Within less than six months Turkey should receive its first floating storage and regasification unit (FSRU), which will be located on the western Aegean coast near the existing onshore LNG terminal at Aliaga. The terminal will have a 5 billion cubic metre capacity, half of which will be available for private companies, according to the latest tender announcement published by the regulator EPDK.

There are plans for at least another four offshore projects dotting Turkey’s western coastline from Canakkale in the Marmara Sea down to the Mediterranean Bay of Anatakya, which could boost supplies and allow enough flexibility for Turkey to start exporting volumes. Although LNG prices were prohibitively expensive after the Fukushima nuclear disaster, they have started to fall thanks to a global oversupply. This means that LNG volumes will be able to compete with pipeline imports on price.

Although Turkey is now in talks with Russia’s Gazprom to build TurkStream – a pipeline that would carry Russian volumes across the Black Sea to Turkey’s domestic market and possibly further to southern Europe, the country’s gains might be greater elsewhere. Firstly, the proposed capacity of TurkStream’s first string will be 15.75bcm/year, only 1.75bcm/year higher than what Turkey already receives through the Western Line. This means that Turkey may not gain extra flexibility, since the string would merely divert the 14bcm/year that Turkey already receives via the Western Line to a different route.

Secondly, if TurkStream is built in full, ie four strings with a combined capacity of 63bcm/year as discussed when the project was launched in 2014, Turkey’s prospect of exporting gas from alternative sources would diminish. This is because the sheer volume of gas imported via TurkStream would minimise the need for other sources. In contrast, Turkey’s LNG alternative and related export opportunities look more promising.

If Turkey’s multiple FSRU projects were to materialise, the country could start exporting any excess volumes to regional markets via its interconnecting pipelines. Thanks to the capacities that are now opening up in eastern Europe, Turkish traders could sell gas anywhere along the Ukraine-Greece corridor as well as allow for reverse flows from these countries in case of supply shortfalls.

Of course, FSRUs are not the ultimate answer in terms of security of supply, but in combination with pipeline volumes imported from Russia, Iran, Azerbaijan and possibly Israel in the future, they should give Turkey significant leverage in the region. This leverage, however, hinges on Turkey building and expanding its interconnection capacity with Bulgaria and Greece, removing its restrictions on import/export licensing rules, publishing much-needed reverse flow tariffs and allowing private companies to become actively engaged in domestic and regional trading.

As gas demand remains weak in eastern Europe, and Turkey's own consumption levels have been falling since 2015, the only way to deal with the gas glut that is building up is to open up borders and allow markets to balance demand and supply. In this context, the changes that are now underway in eastern Europe should encourage Turkey to consider its long-term energy vision as well as the role it could play in its immediate neighbourhood.

Turkey and the energy transit question

Natural Gas Europe, *31.08.2016*

For foreign and security policy analysts, pipelines tend to be the entry point into the world of energy. Pipelines create dependencies between countries, pipelines stay for decades, and pipelines have a highly symbolic political value. In the European energy security debate, gas pipelines also have an identity function:

You either support freeing Europe from its dangerous addiction to Russian gas by backing the Southern Gas Corridor or you blindly follow the Kremlin's breadcrumbs into the Nord Stream/South Stream-energy trap. Critical differentiation is rare.

Today, controversies over pipeline politics have a rather anachronistic flavor. This is mainly due to the growing flexibility of European—and partially global—natural gas markets in light of the massive increase in LNG supply, interconnectors, and spot market trade. This new market environment has not only changed the relationship between producers and consumers but has also altered the political and economic leverage of transit countries. This is especially important when looking at new transit countries, Turkey being a prominent example.

Nowadays, transit countries are not just dependent service providers; they can also have a profound influence on the market share of a supplier. This leverage can be used as a vehicle to negotiate higher transit fees depending on the available flexibility of switching between markets and suppliers on both sides.

The example of Ukraine as a transit country illustrates this quite well: without alternative supply routes, Ukraine can determine the market share of Russian gas in Europe (approximately 60% of Russian export capacity to the EU is via Ukrainian territory.) Once a pipeline is constructed, the temptation for rent-seeking in transit countries—and transit control power—is huge. Therefore, a suppliers' interest in the physical diversification of transit routes is understandable. This applies as much to the future gas supply architecture of Southeastern Europe as it does to the Nord Stream/Ukraine debate.

With the realization of the Trans-Anatolian Pipeline (TANAP)—a smaller version of the originally planned Nabucco Pipeline and now a Southern Gas Corridor project—two new variables will enter the equation of European energy security. First, natural gas from Azerbaijan could reach European markets for the first time around 2019. Second, Turkey will obtain the position of a transit country for European gas imports; admittedly with limited influence, since only 10 billion cubic meters per year are foreseen for the European market (between 2-3% of total EU gas consumption in 2014.)

In addition to the TANAP project, the recent easing of tensions between Turkey and Russia has revitalized debates about the construction of Turkish Stream, a project that was initiated after a direct pipeline connection between Russia and Bulgaria through the Black Sea ("South Stream") was cancelled in 2014 due to regulatory conflicts between Gazprom and the European Commission. Turkish Stream would mainly supply the Turkish market, but could also bring gas destined for the EU market to the Turkish-Greek border.

Moreover, should gas exploration in the Eastern Mediterranean Sea south of Greek Cyprus be commercially and technologically feasible, project developers will be tempted to think about a possible pipeline project serving the Turkish market and potentially re-exporting gas to Southeastern Europe. The Turkish corridor would also be mandatory for all hypothetical deliveries from Iraq, Iran, or Central Asia.

While some analysts positively describe these developments as the creation of the "Gas Hub Turkey," one could also reframe it as the potential rise of Turkey as a major transit country for (Southeastern) European gas supply. There has been very little debate so far on the subsequent security implications.

With the potentially growing role of Turkey as a transit corridor for European gas supplies, the implications could be twofold. On the one hand, future relations between Azerbaijan and the EU will be strongly influenced by Ankara's role as the middle man in transporting gas. On the other hand, Turkey could also gain a significant position in EU-Russia gas relations—smaller, but still comparable to the situation of Ukraine today.

The threat of Turkish influence over how much Azeri or (some of the) Russian gas would enter European markets and the potential for rent-seeking in transit fees looks troubling in the current political environment. The willingness of Turkey's government to link issues such as refugee treatment, visa liberalization, and financial transfers, as has happened recently, should serve as a warning.

This leads to the conclusion that both Russia's and Europe's interests would be best served if Turkey were kept out of bilateral energy relations in the future; a possibility that can only materialize if Turkey does not assume a gate-keeper role for several suppliers simultaneously.

Currently, however, the opposite is a very realistic scenario. Since the cancellation of the South Stream project, Russia has declared an unwillingness to deal with the "politically motivated" regulation of the EU Commission on the matter of Southeastern European gas supplies, and only a few EU politicians have shown interest to engage in the issue again. This has not solved any problem though, since competition between different gas suppliers as well as control over access to the EU market would be transferred into the hands of Turkish authorities in the future.

Therefore, resuming the debate about a smaller version of a direct Russia-EU-link through the Black Sea, which would exclude Turkey, should be seriously revisited by European and Russian stakeholders alike. Provided, of course, that the regulatory control of the third energy package fully applies on EU territory.

Turkey seeks Israeli deals

Natural Gas Europe, *30.08.2016*

A delegation of Turkish businessmen headed by Ahmet Zorlu, visited Israel last week in the wake of the two countries' reconciliation agreement.

Zorlu Group, one of the biggest in Turkey, is already involved in the Israeli energy market through a 25% holdings in Dorad, a new gas-fired generation plant, in partnership with Israeli Edeltech. The plant was built as part of the reform in the local electricity market. Zorlu, who is regarded an ally of Mr. Erdoğan took part in an inauguration ceremony for two power plants and met Yuval Steinitz. In the ceremony, Zorlu said that Turkey was waiting for Israeli natural gas.

Steinitz said that he hoped that the normalization would lead to stronger economic ties between Israel and Turkey in general, and in particular to the export of Israel's gas to Turkey. Even during the six-year crisis between Israel and Turkey, economic ties remained strong and the trade between the two countries grew continuously.

According to another report, more practical negotiations between Turkish and Israeli companies started last week when a senior Turkish executive visited Israel for talks. According to earlier media reports, a 15-strong Turkish consortium will stump up $2.5bn to finance a 500-km sub-sea pipeline from Leviathan to Turkey.

Greek Cyprus, Egypt start gas trade talks process

Natural Gas Europe, *31.08.2016*

Greek Greek Cyprus and Egypt have signed the first of three agreements that involve gas being transported from Greek Greek Cyprus' exclusive economic zone (EEZ) to the LNG terminals of Egypt or for domestic demand in Egypt's power stations. In a joint statement August 31 they said:

"Governments of Greek Greek Cyprus and Egypt decided to speedily proceed with discussions on an Intergovernmental Agre ement for the pipeline from Greek Cyprus to Egypt, which will be intended to facilitate the realisation of the project within the maritime areas of jurisdiction of the two countries, Egypt and Greek Cyprus.

Cooperation in the oil and gas sector between the two countries will further deepen the excellent relations between Greek Cyprus and Egypt to the mutual benefit of the peoples of Greek Cyprus and Egypt, and will also further unlock and promote the potential of the Eastern Mediterranean as a whole."

The agreement sends clear messages about the direction of Greek Cyprus' energy planning, which is at a very difficult period owing to developments in the area. Based on these plans, it is expected that Cypriot gas could be exported during the period 2020-2022. But as Greek Cyprus' energy minister Giorgos Lakkotrypis said, this will require entering into firm, commercial, gas sales agreements first. This does not appear to be any more likely or imminent.

Lakkotrypis said the agreement creates a secure investment framework for the transport of natural gas to Egypt. He added: "Essentially today we signed an agreement that provides that the two countries will respect the provisions of any trade agreements to be made in the near future… We hope that this agreement will assist and accelerate trade agreements… creating a secure investment framework for the sale of natural gas from Greek Cyprus to Egypt."

Egypt's minister for petroleum Tareq El Molla echoed this by stating "We are very excited. We look forward to the next steps that will be part of the trade agreements to be developed soon." He also expressed the desire of Egypt to become an energy hub in the eastern Mediterranean region. It is a political agreement between the two states facilitating the export of gas from Greek Cyprus to Egypt. It was stressed that the development confirms that the process of exploitation of Greek Cyprus gas is now moving forward.

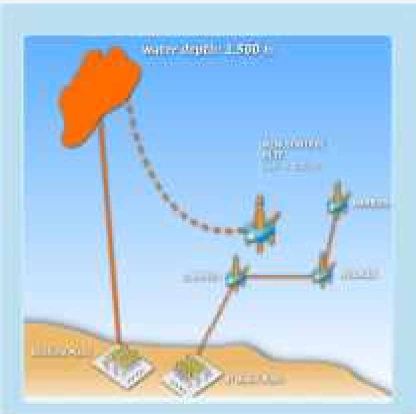
Following discovery of Aphrodite, Greek Cyprus and Egypt entered into negotiations in August 2014 for the joint exploitation of natural gas deposits and an agreement was signed in September that year. This was followed by a tripartite Egypt-Greek Cyprus-Greece meeting in Nicosia in November 2014 after which Sherif Ismail, Egypt's then oil minister, said 'Cairo would speed up talks to pipe Cypriot gas for domestic needs and possible re-export.'

In February 2015 Egypt and Greek Cyprus signed another MoU to study over a six-month period technical solutions for the transport of gas through a marine pipeline from the Cypriot Aphrodite field to Egypt. The Egyptian petroleum minister hailed this as the start of cooperation between the two countries in importing gas, but clarified that there is no agreement over the price of the imported gas, and that this will be negotiated after the sixth-month period. The six months have come and gone and no result has been forthcoming.

More agreements followed in August and October 2015 and in November BG – now owned by the Anglo-Dutch major Shell – joined the block 12 consortium opening the way for transporting gas to its LNG plant at Idku for export to Europe. However, despite the political will and company support none of these accords progressed to any commercial deals as the economics do not add up, in today's low gas-price environment.

ENI's fifth Zohr well 'a success'

Natural Gas Europe, *02.09.2016*



Italy's Eni said September 1 it had drilled its fifth well on Egypt's giant offshore Zohr gas field. Zohr 5x was successfully drilled to a final depth of 4,350 metres, 12 km southwest of the discovery well Zohr 1x and in water depth of 1,538 m.

The new well confirmed the potential of the Zohr field at 30 trillion cubic feet (850 billion cubic meter), said Italian Eni energy company, proving the presence of a carbonatic reservoir and gas accumulation also in the south-west of the Zohr mega-structure, with a 180-meter continuous hydrocarbon column.

The well was also successfully tested opening 90 meters of the reservoir section to production. Data collected during the test confirmed the great deliverability of the Zohr reservoir, in line with the Zohr-2 well test, producing more than 50mn ft³/d, limited only by the constraints of the drilling ship production facilities.

In the production configuration, Zohr 5x is estimated by Eni as capable of delivering up to 250mn ft^3/d. The drilling campaign on Zohr will continue in 2016 with the drilling of the sixth well that will ensure the accelerated start up production rate of 1bn ft^3/d. Eni said it was making "steady progress of the project execution is confirming the schedule expected to reach the first gas by the end of 2017." Eni, through its subsidiary IEOC, holds a 100% stake in the Shorouk Block. Petrobel is operating the activities on behalf of the Petroshorouk company, an equal joint venture between IEOC and state-owned Egyptian Natural Gas Holding Company (Egas).

Separately, Eni said it has now paid GasTerra security in order to release Eni's stake in its Dutch subsidiary. On July 20 as part of a long-term gas contract dispute with the Dutch seller, against whom it had lost an arbitration case, Eni said Gasterra had seized Eni's participation in Eni International BV, for the amount of the payment requested (equal to €1.01bn). Eni did not agree with the arbitration court's judgement and refused to pay.

"In accordance with an agreement between Eni and GasTerra on the basis of which Eni provided alternative security to GasTerra by means of a bank guarantee, GasTerra has now lifted the provisional seizures," Eni said September 2.

Israeli powergen to burn more gas

Natural Gas Europe, *29.08.2016*

Israel's energy minister, Yuval Steinitz has ordered the closure of four coal-fired power generation units and their replacement with two new natural gas-fired combined-cycle power generation units. He announced his decision following a public campaign to shut down the 40-yr old units that are part of Orot Rabin, the biggest power generation plant in Israel, near Hadera, north of Tel Aviv.

As part of his decision, Steinitz cancelled an NIS 8bn ($2bn) scheme to install smoke scrubbers in coal-fired units. The plants will however be maintained as back-up generators for the grid.

Steinitz's decision will take at least five years to implement. Two gas-fired power generation units are still to be designed and built and new sources of natural gas have yet to be developed and come online. Steinitz hopes the decision will hasten the realisation of the Regulatory Natural Gas Framework since it will create a further 1.5-2bn m^3/yr demand for natural gas in the domestic market.

Steinitz' announcement is part of the energy ministry's policy to reform the state monopoly, Israel Electric Corp (IEC). When the decision is implemented, up to three quarters of power generation will depend on natural gas, one of the highest rates in the world, and certainly the highest among OECD member states. At the beginning of 2016 Steinitz ordered the IEC to use 15% more gas, replacing an equivalent amount of coal.

Delek to sell Tamar stake through special purpose CO

Reuters, *01.09.2016*

Israel's Delek Group, is set to sell its 31.25% holdings in Tamar Partnership through a special purpose company. The company plans to transfer all its Tamar holdings to the special purpose company and the go to an initial public offering in either New York or London.

First details of Delek Group's plan to divest its holdings in Tamar were revealed this week by Chief Executive Officer Asaf Bartfeld during an analysts' call following the filing of the group's second quarter results. According to the Regulatory Natural Gas Framework Delek has to sell off all its Tamar holdings within six years of the Framework's approval.

Noble Energy, the biggest stake holder in Tamar with 36% and the operator, has to sell down to 25%. In July Noble concluded a deal to sell 3% of Tamar to Harel Group, one of Israel's biggest insurance group in a $369mn deal that values the project at $12.3bn, according to Noble. The deal has still be approved by the regulators but set the benchmark for Delek's sale.

"We have a few options. As you know Noble has to divest 11% but we have to sell all our holdings in Tamar, so it's another story," Bartfeld said. "One of the plans that we are looking at is to establish a new legal entity, a partnership or a company, and take this company to the capital market. "Most of the 28% [of Tamar] are pledged to the Tamar Bond, we have 3% free," he said referring to the $2bn bonds issue from two years ago which are secured against revenues from Tamar. Bertfeld said that Tamar was too big for the Israeli capital market to absorb it.

Bartfeld also referred to offtake agreements and said that company was negotiating with Union Fenosa Gas (UFG) and Shell but added that there is "nothing we can talk about." As for Jordan, he said that a deal with Jordan's Nepco, the Jordanian Electric Company, for an annual 3-4bn m^3 PSA is "especially important for the development of Leviathan." However, he said that despite the deal's approval in the Jordanian Parliament, it is not a done deal yet. "The deal is not signed, we hope it will be signed very soon," Bertfeld said. "There are some issues. It is not something that I know and not telling you. Just I don't know exactly."

According to an analyst who preferred to remain anonymous, the solution to the problem may pose a hurdle as ownership transfer normally means bondholders are entitled to demand an early repayment.

Shana: First train of phases 20&21 refinery operational

Shana, *29.08.2016*

The first train of the refinery facilities of phases 20 and 21 of the supergiant South Pars Gas Field came online on Sunday once the gas recovered from phases 6, 7 and 8 of the field was injected to the facility.

The refinery sweetens the sour gas it receives from the phases for injection to the national gas distribution trunklines. Phase 20 and 21 development projects are being carried out in two offshore and inshore sections and are aimed at production of 2bcf/d of natural gas and 80,000 b/d of gas condensate. Oil Industries' Engineering and Construction is developing the projects under an EPC contract.

Operator of the phases Alireza Ebadi has said the two projects will become operational by the end of the current calendar year to late March 2017. The second train of the refinery is ready for startup as well; he has recently said. A while ago, the platform of phase 21 was installed at its offshore spot. The structure will start gas recovery by January 2017.

Iran signs confidentiality agreements with IOCS

Bloomberg, *31.08.2016*

The NIOC has said that seven confidentiality agreements have been so far signed with international companies on carrying out studies related to oilfields. They are: France's Total, Indonesia's Pertamina, Russia's Lukoil and Zarubezhneft, Austria's OMV, and Germany's Wintershall.

The contracts grant the signatories access to confidential components that they wish to share with one another for certain purposes, but not with third parties. "These companies are to provide us with results related to the studies, however we will have no obligations to grant the development of the oilfields to them," he explained.

In fact, by signing the agreements, NIOC will benefit from consultative services of the companies on studying the oilfields, he noted. Iran has yet to clarify the issue of studies in the confidentiality agreements, but last week an official with Iran's oil ministry told NGW that Total plans to study the pressure fall in South Pars, the world's largest gas field Iran shares with Qatar. That follows a confidentiality agreement worth $2.5mn with that Total signed in March to study the South Azadegan field.

Kardor also said that the first tender for new model of oil and gas contracts, known as Iran Petroleum Contract or IPC, will be held in the next Iranian month, starting September 22. It is likely that the contract will be related to South Azadegan field, he added. South Azadegan oilfield, which is jointly held with Iraq, will be developed in several phases. The Iranian side of the field is producing 50,000 b/d and is projected to rise to 320,000 b/d with 132 new wells in two phases. Iraq is producing 210,000 b/d from the field.

Iran has prioritized developing five oilfield it shares with Iraq, namely North Azadegan, South Azadegan, North Yaran, South Yaran, and Yadavaran. Iran is producing a total of 225,000 b/d from the fields and plans to raise the figure to 700,000 b/d by March 2019. Kardor further said that three IPC-based deals will be signed by the end of the current Iranian year (March 2017) and the deals will attract some $10bn foreign investment. Last December, Iran introduced 50 oil and gas fields within the framework of IPC to foreign companies.

Minister: Pakistan needs to get on with pipeline

Natural Gas Europe, *29.08.2016*

The IP gas pipeline is the best way to help Pakistan bridge gas deficit and the project should be completed at the earliest opportunity, Hafiz Pasha told IRNA in an interview.

"This project has to be revived at the earliest, because it is the most viable and feasible project for Pakistan," he told the Iranian news agency last week. The gas price is very attractive and it should be the first priority, he said. The 1,900-km pipeline project was delayed by sanctions on Iran. Although Iran has almost completed its section of the line, Pakistan is yet to start building the pipeline from the border because of US pressure.

Iran's gas exports were to start on January 1, 2015 but Pakistan called for an extension of the project. Recent media reports suggest that the two parties are negotiating amendments in the gas deal. The current agreement was signed in 2009.

Many believe that with price of LNG so low, Islamabad has shifted its focus to that as a way of meeting domestic demand as the pipeline still attracts some sanctions. Officials from both Iran and Pakistan have time and again said both countries are determined to complete the project; but with finance hard to come by, the future of the project looks extremely uncertain.

The south Asian nation began importing LNG last year. This year, two Pakistani companies signed long-term LNG import deals with Qatar and both state owned and private entities have been busy building LNG import infrastructure. The country's first floating storage and regasification unit became operational in March 2015 and last week BW Group and Pakistan GasPort signed a deal for the second floating unit, which is expected to be commissioned early-2017.

Chinese and Russian companies are moving forward with their plans to build the pipelines needed to transport re-gasified LNG to major cities in the north. The government has made it clear that LNG will play an increasing role in Pakistan's energy economy. Pakistan's has been facing a massive gas shortage which has severely impacted its industrial activity.

SOCAR joins new Adriatic pipe project

Natural Gas Europe, *29.08.2016*

Four western Balkans nations signed a memorandum of understanding with Socar on co-operation on building the IAP on the sidelines of a Dubrovnik forum 25-26 August.

The declaration of intent to develop the 5bn m³/year line was originally signed in 2007 by Croatia, Montenegro and Albania. The length of the line from Split in Croatia to Fier in Albania will be around 530 km and cost around €610mn. Socar will join Croatia, Albania, Bosnia & Herzegovina and Montenegro in the project which will include a section of the TAP designed to bring gas from Shah Deniz 2 field in the Caspian Sea to EU through the so-called SGC after 2020.

Socar's goal is to connect the Caspian Sea and the Adriatic Sea, the head of Socar Balkans, Murad Heydarov, said after the signing ceremony. "The SGC, which includes the Ionian-Adriatic gas pipeline is an important part of our plans, we have good co-operation with the countries involved in this project," he said, according to Socar sources.

Croatia's economy minister Tomislav Panenic said that the future pipeline would provide gas supplies for southeastern Europe. "We have defined our joint initiative for the development of the Ionian-Adriatic gas pipeline as a route that will make sure that these markets are provided with gas. We hope that this route will be a connection between the north and the south and that this may pave the way for a full liberalisation of the gas market in Europe," he said, Croatian news agency Hina reported.

Montenegro's economy minister Vladimir Kavaric said that IAP was the only opportunity for the gasification of Montenegro and "the government is ready to do everything to accelerate and successfully implement the project." According to Bosnia & Herzegovina's foreign trade minister Mirko Sarovic, "Bosnia & Herzegovina supports this regional project and approach and ask the partners to ensure that a section of the route goes through Bosnia & Herzegovina."

According to preliminary design IAP aims to connect existing transmission system of Croatia via Bosnia & Herzegovina (offshore), Montenegro and Albania to the TAP. The Baltic-Adriatic-Black Sea (BABS) forum brought together six presidents and high-ranking government officials from 12 EU countries and Albania on August 25-26 in Dubrovnik, Croatia. A panel discussion at the "Strengthening European energy security" looked at the benefits of energy cooperation in BABS and the role of LNG terminals linking north and south Europe.

Connecting the LNG terminal in Poland with one planned on the island of Krk in Croatia is among the energy projects that BABS region countries want to implement in order to boost competitiveness and development, Croatia's president Kolinda Grabar-Kitarovic and Poland's president, Andrzej Duda, said addressing forum at the opening ceremony August 25.

President Duda pointed out the importance of energy connections."The dominance of a single supplier for the region is harmful and dangerous", he said adding that development of the gas corridor between the north and the south, as well as the LNG terminal on the island of Krk are important. The next meeting of BABS will take place in Wroclaw in June 2017.

First Shah Deniz 2 jacket leaves Baku shipyard

Reuters, *01.09.2016*

The first jacket for one of the BP-operated Shah Deniz Stage 2 platforms sailed away from the Heidar Aliev BDJF for offshore installation September 1. In attendance was the president of Azerbaijan whose country is the starting-point of one of the world's most complex integrated gas projects.

The transportation, launch, positioning and pile installation activities of the production and risers' platform jacket structure are expected to take around 40 days to complete. The platform jacket, built by the BOS Shelf, Star Gulf and Saipem consortium using local construction infrastructure and facilities.

Over 4,700 people including sub-contractors and specialist vendors were involved in the construction works and not a day was lost over the two years of work to accidents. BP's Shah Deniz 2 projects head Ewan Drummond said the "first jacket sail away is an important milestone and we are pleased to have achieved this as we move towards completion of other areas of the project. I would like to thank the government of Azerbaijan and [state oil company] Socar for their support and cooperation in moving this giant project forward."

When complete and operational, the field will add 16bn m³/yr to Azerbaijan's gas exports, snaking in new pipelines across the Caucasus, Turkey and southern Europe before reaching Italy early next decade. Of the total, 10bn m³/yr are destined for Europe and 6bn m³/yr for Turkey.

Gazprom creates new NGV subsidiary

Natural Gas Europe, *29.08.2016*

Gazprom group said August 26 that it had established a new company two days previously in Berlin, called Gazprom NGV Europe.

The new company is a wholly-owned subsidiary of Gazprom Germania, also Berlin-based, and will continue its former compressed natural gas (CNG) business. Gazprom NGV Europe operates 50 CNG filling stations in Germany and has already constructed a further ten in the Czech Republic and Poland. This company will fulfil all the regulatory requirements of the German Energy Act, which stipulates the separation of trade and transport.

Uwe Johann from Gazprom Marketing and Trading has been appointed as managing director of the new company. Trade association NGV Europe said in its latest annual report there are 1.3mn natural gas vehicles (NGVs) across Europe and more than 3,600 NGV refuelling points, of which about 100 for are refuelling vehicles that run on LNG. EU policy is to promote NGVs and many firms including France's Engie, Spain's Gas Natural Fenosa and several German utilities, as well as Gazprom, are expanding their refuelling networks.

Gazprom sells more but earns less

Natural Gas Europe, *30.08.2016*

Russian gas export monopoly Gazprom saw its profit drop by about a tenth in H1 2016 compared with the year before, falling from Rbs 691.3bn to Rbs 625.4bn. Higher costs and lower oil prices were the main reason it gave.

It said its "continuing strong financial performance combined with a unique asset base ensure both dividend payments and the ability to fund further investment in major value adding projects." The biggest projects in Gazprom's in-tray are eastern Siberian upstream gasfield developments and the Power of Siberia export line to China; and Nord Stream 2 pipeline.

Net sales of gas rose by Rbs 136.51bn, or 8%, from Rbs 1,618.8bn to Rbs 1,755.3bn ($27bn). Net sales of gas to Europe and other countries – which it also calls the 'far abroad' and includes Turkey – rose by 19%, to Rbs 1,128.3bn ($17.4bn). This rise was driven by the 36% increase in volumes of gas sold: 109.4bn m^3 to Europe and other countries, up from 80.4bn m^3 in H1 2015. That factors in an increase of 49% to 58.1bn m^3 to these markets during January-March 2016, disclosed on August 10.

Gazprom said that H1 2016 sales to its customers in both the Russian Federation and the former Soviet Union were down, collectively by 14bn m^3. The average Russian ruble price (including excise tax and customs duties) fell by 18% compared with the same period of the prior year. Sales to Former Soviet Union countries fell 27%. The change was owing to less gas at a lower price. Net sales of gas in the Russian Federation fell 1%, as although the average ruble price rose 8%, it sold 9% less gas.

Its share of profits from associates and joint ventures fell by Rbs 27.6bn to Rbs 33.8bn ($521mn), mainly resulting from Sakhalin Energy Investment Company – the integrated LNG project in Russia's far east – contributing Rbs 33.17bn less than last year. This was partly compensated by Rbs 15.52bn more from Gazprombank and its subsidiaries.

Charge for impairment and other provisions rose by Rbs 33.85bn or 114 % for the six months, mainly driven by an increase of charge for impairment allowance for doubtful trade accounts receivable of Naftogaz Ukrainy; and charge for impairment allowance for doubtful prepayments.

The cost of transiting gas, oil and refined products rose by a quarter to Rbs 303.79bn ($4.7bn), up from Rbs 242.83bn for the same period last year. This increase was mainly driven by an increase in transit of gas through the territory of Ukraine denominated in rubles and the activity of the Gazprom Germania Group, which carries out Gazprom's trading and supply activities in Europe.

Weekly overview: Low oil price, UK energy and OMV

Natural Gas Europe, *29.08.2016*

Cheniere The end of the summer holidays looms, and with it comes the grinding of gears as brainpower is redirected from pleasant distractions back towards stubbornly difficult problems:

The oil price remains low, despite talking up the prospects of an Opec-led production squeeze when ministers meet in Algeria next week; the UK must decide soon what is to be done with Hinkley Point C; and Gazprom's foreign partners must decide how to replace the planned Nord Stream 2 AG joint venture with something else that brings in useful revenues over a long period.

The low oil price is behind the woeful economic outlook for Scotland, as shown in a new government report. The owner of perhaps 85% of the oil and gas reserves on the basis of the likeliest angles of the median line, Scotland, which earned notionally £1.8bn in 2014-15, earned about 97% less in 2015-16, thanks to decommissioning charges. Shell for example earned back earlier taxes to offset the costs of dismantling Brent. The UK is trying to maximise the economic recovery of the reserves, but absent a sharp uptick in the price, it will be an uphill struggle keeping the essential infrastructure ticking over until the reserves further upstream have been safely brought ashore.

Again in the UK, the formality of Theresa May's new government's decision to reread the terms of the Anglo-Franco-Chinese Hinkley Point C (HPC) nuclear plant contract now looks more substantial. There has been more analysis of the size of the subsidy it would receive from UK customers, and news that in the US, the FBI has been investigating some employees at the Chinese firm involved, Chinese General Nuclear, for suspected industrial espionage activities carried out in the US. If the plant goes ahead China would go on to build more plants with greater ownership than its one-third stake in HPC, under an agreement China reached with David Cameron's government.

Adding further fuel to the flames was a report this week by the Energy and Climate Intelligence Unit in the UK, which asked if "Hinkley C does not happen, for whatever reason, does it matter?" It concluded that HPC was "not essential. Alternatives include four big offshore wind farms (additional to those the UK will build anyway), or three additional interconnecting cables. Using electricity more efficiently and productively would remove the need for 40% of HPC and of course there is the possibility of gas-fired plants and demand-side response (DSR).

It said one solution for meeting peak demand without HPC would be to split the 3.2 GW roughly equally between DSR, gas plants and interconnection. To provide the same de-rated capacity, this system would require around 3.7 GW of DSR, 1.6 GW of interconnection and 1.2 GW of peaking gas capacity, at a cost of £3.2bn, around one-sixth the cost of Hinkley, with these savings feeding through into consumer bills.

Other, conventional nuclear plants are jockeying for position: Hitachi, the Sunday Times reported August 28, has appointed a new CEO for its nuclear subsidiary Horizon Nuclear Power. Duncan Hawthorne is to secure a commitment from the government to guarantee a price for three decades or more. That will be a very different contract because as a private investor it can take less risk than the EDF-led HPC. Also unlike EDF, its technology is mature. “It’s not a paper reactor, it’s a real reactor,” he told the paper.

Gas-fired power too is on the agenda: EPH, the Czech owner of the UK Eggborough power plant, built to run on the Selby coalfields, is converting to gas, demolishing the structure to build a 2-GW combined-cycle gas turbine. That too will most likely require financial underpinning, secured perhaps by a capacity mechanism so that it is paid enough no matter how low its actual output.

Thanks to a combination of the carbon price floor – a UK invention to tilt the playing field against coal in the absence of a high emissions trading scheme price – and low gas prices, over half of UK power production in 2Q 2016 came from gas. According to latest national statistics, gas provided 50.9% of 2Q electricity generation by major power producers, with nuclear at 24.2%, renewables 18.1% and coal only 6.8% – its lowest ever percentage.

On the continent, there was another meeting between the CEO of Austrian OMV Rainer Seele and his counterpart at Gazprom, Alexei Miller. They discussed Gazprom’s importance in Europe and the need for Nord Stream 2 without mentioning the Polish decision to ban the joint venture that would operate it.

OMV, as prospective partner in the planned Nord Stream 2 AG, might have been expected to comment on how the companies involved planned to circumvent the fatal blow that the Polish competition agency struck late in mid-August. However, whatever was discussed behind closed doors, there was no mention of it in the release. They did however discuss the asset swap. This involves upstream assets in Russia in exchange for upstream assets in Norway. Seele was not keen to comment on progress at the company’s Q2 2016 results conference. He said the Norwegian regulator would be notified of the deal when OMV and Gazprom had agreed its terms.

Back on its home turf, OMV is nearing a solution with utility Verbund over a gas contract that governed supplies to an Austrian power plant. While nothing has been revealed over the details of this privately disputed agreement, Verbund stands to record a one-off gain, suggesting that the seller has recognised that power prices were too low to justify the gas price and is making a rebate which Verbund seems likely to accept.

The two parties are also planning to co-operate in greener energy and research into hydrogen cells. Thus OMV joins other European incumbents such as E.ON, Engie and RWE in adapting to the energy transition, while still focusing on oil production and other old-school activities.

Statoil starts North Sea Project 4 months early

Natural Gas Europe, *30.08.2016*

Statoil said August 30 that its Gullfaks Rimfaks valley (GRD) project has come onstream four months ahead of schedule. The development cost ended up Nkr 1bn ($120mn) less than originally estimated when its plan was submitted in late 2014, reducing costs from Nkr 4.8bn to Nkr 3.7bn ($446mn).

The fast-track development opens up recoverable reserves of some 80mn barrels of oil equivalent (boe), mostly gas. Statoil is operator (51%), backed by Norwegian state holding Petoro (30%) and Austria's OMV (19%). The development consists of a standard subsea template with two simple gas production wells, and possibilities for tie-in of two more wells.

The well stream is connected to the existing pipeline leading to the Gullfaks A platform, some 5-15 km away. Gas and condensate are transported through existing pipelines to the processing plant at Karsto, then onward to European markets. "Volumes from Gullfaks Rimfaksdalen help us reach our ambition of maintaining production and a high activity level on the Norwegian continental shelf beyond 2030," said Arne Sigve Nylund, Statoil's executive vice president for Development and Production Norway.

Separately, Statoil said August 25 that its Njord A platform arrived at the Kværner Stord shipyard that day, where it will be reinforced and renovated for production beyond 2030. When the field was developed, it was scheduled for production only until 2013. Now it is expected to produce for at least ten more years. Its overall expected recovery of oil and gas is now 333mn boe, much higher than the 200mn boe in its original plan, thanks to tying-in the Snilehorn and more recent finds. Statoil operates Njord with 20%; Engie has 40%, DEA 30%, Faroe Petroleum 7.5% and Germany's VNG Norge 2.5%.

Connecting Europe: Security through capacity

Natural Gas Europe, *29.08.2016*

The Atlantic Council of Washington DC has produced a major report stressing the need for Europe to develop its gas interconnections if it is to benefit from increasing competition between Russian pipeline gas and US LNG – and cope with any major gas supply crisis.

The report, written by John Roberts, specifically recommends coordination of the EU's current PCI to ensure that substantial volumes of gas can flow freely between the Baltic, the Adriatic and the Black seas. An initial version of the report was presented August 26 at the Dubrovnik Forum, a meeting convened by the president of Croatia, Kolinda Grabar-Kitarovic.

One of the report's key recommendations, the development of the Ionian Adriatic Pipeline from Albania to Croatia, was the subject of a memorandum of agreement signed at Dubrovnik August 29 between, on the one hand, Croatia, Albania, Bosnia-Herzegovina and Montenegro, and, on the other, the Azerbaijani state oil company Socar, for a connection between the IAP and the €6bn Socar-backed project to build the Trans Adriatic Pipeline from Turkey to southern Italy.

The report makes two major recommendations. The first is that the Action Plan for Central Eastern and South Eastern Connectivity (CESEC) approved in Dubrovnik on July 10, 2015 should be fully implemented. The second is that there should be an integration of existing projects to develop what the author calls a "Backbone Pipeline" to connect the existing Polish LNG regasification terminal at Świnoujscie on the Baltic coast, with Croatia's planned LNG terminal at Omisalj in the Adriatic, together with an effective connection through to the Black Sea and the Aegean, possibly based on an expansion of the Bulgaria, Romania, Hungary and Austria (BRUA) scheme.

The first recommendation requires further financial and diplomatic support for six of the CESEC Action Plan projects, since the seventh, the development of the Trans-Adriatic Pipeline (TAP) from Turkey's border with Greece to southern Italy, is already well under way.

The six remaining projects are:

- The Interconnector Greece-Bulgaria (IGB);

- The Interconnector Bulgaria-Serbia;

- The phased reinforcement of Bulgaria's domestic system to allow utilization of both interconnections that are already in existence and those under development;

• The phased reinforcement of the Romanian domestic system to allow utilization of existing interconnections and interconnections being developed, including necessary reinforcements at those interconnection points in adjacent systems;

• An LNG terminal in Croatia, with potential for phased development;

• An LNG evacuation system from Croatia toward Hungary together with the necessary reinforcement of Croatia's domestic system.

The second major recommendation essentially requires development of an interconnector capable of carrying around 15bn m³/yr between Lwowek in Poland and Slavonski Brod in Croatia, together with a crossover point at Varosfold in Hungary so that it can operate in conjunction with the BRUA system and a connection to the main central European hub at Baumgarten.

Roberts stresses that what is needed is a system of sufficient capacity both to boost competition within Europe and to serve as an emergency distribution system should one major supplier, such as Russia or Norway, for one reason or another prove unable or unwilling to continue deliveries.

The Backbone concept is presented as a way of upgrading existing and planned interconnections in a coordinated manner to serve both commercial purposes and the energy security of Europe as a whole. The report also states that there is a need to ensure backhaul – reverse capability – on the Brotherhood system that brings the largest volumes of Russian gas to Europe via Ukraine.

The report also tackles the controversial issue of how to finance pipeline development in Europe, and the problem of tackling corruption, particularly corruption arising from a country's reliance on a single supplier. In addition, it addresses progress in ensuring an end to the "island" status of the northeastern Baltic members of the European Union: Estonia, Latvia, and Lithuania.

Karsto gas leak report finds faults

Natural Gas Asia, *30.08.2016*

PETROLEUM SAFETY AUTHORITY
NORWAY

Norway's Petroleum Safety Authority last week said its investigation of a gas leak onshore in January 2016 revealed a number of regulatory breaches.

The gas leak was detected in the Statpipe receiving area at its major onshore gas process plant at Karsto late on January 7. A near-complete fracture occurred in an instrument fitting with an interior tube diameter of 9.1 mm. When the leak started, the pressure in the affected system was around 140 bar. The initial leak was estimated to be 1.3 kg/second. The gas leak lasted for 9.5 hours and the leaked volume is estimated at 22 metric tons.

The reason that the leak lasted so long was an absence of pressure relief opportunities from the control room for the processing segment where the leak occurred – due to a fatigue fracture in a free-standing instrument fitting pipe branch, arising from bend-stresses from high winds combined with lack of adequate pipe supports, plus the system's natural frequencies and vortex-induced vibration at normal wind speeds.

No-one was injured in the incident. However, PSA Norway said that, had personnel had been in the proximity of the leak in the event of ignition, this could have caused serious personal injuries and potential fatalities. Its investigation of the incident has identified non-conformities linked to mechanical bracing of instruments and other points, and the operator –state-run Gassco, with Statoil as its technical services provider – has been asked to explain how these will be dealt with.

Separately on August 29, Statoil said that the breakeven price for phase 1 of its Johan Sverdrup oil development is now below $25/b, with its capital cost of the giant North Sea project now estimated at Nkr99bn ($11.9bn), which is Nkr24bn less than when the plan for development (PDO) was submitted. Phase 1 production capacity is now 440,000 b/d oil, whereas the PDO had estimated it between 315,000 and 380,000 b/d.

The estimate for the full-field investment has been improved from a range of Nkr170–220bn in 2015 to a 2016 value of Nkr140–170bn. Expected full production capacity is raised to 660,000 b/d, compared with the original PDO which estimated 550,000–650,000 b/d; however final concept selection for future phases has yet to be formally decided.

Meanwhile Russia-backed DEA said August 29 it is finalising its PDO for the Zidane gas development in the Norwegian Sea, ready for submission this autumn. It will be DEA's first as an operator in Norway. DEA Norge chief Hans-Hermann Andreae said: "With development starting this year, production start is planned for the year 2020." The development concept consists of four producers utilising a 4-slot subsea template tied back to the Heidrun platform. Gas will be processed in a new gas module before it is transported via Polarled to Nyhamna Gas Terminal.

Norwegian upstream costs fall 40+%

Natural Gas Europe, *30.08.2016*

Lower costs and simpler field designs have helped cut the cost of Norwegian field development – but not all cost savings are good, warns the Norwegian Petroleum Directorate, official institution of Norway for managing petroleum related issues.

Over the last two years, the price tag for developing a field on the Norwegian shelf has declined by an average of more than forty per cent (40%), according to the Norwegian Petroleum Directorate's (NPD) analysis of eight planned developments nearing start-up. Norway is one of the world's more expensive places to produce oil.

The investment estimates for the Utgard, Oda, Zidane, Trestakk, Snilehorn, Johan Castberg, Snorre Expansion and Johan Sverdrup Phase 2 projects have fallen from about Nkr270bn to Nkr150bn, according to the operating companies' own calculations. The downward adjustments have been made in connection with various decision phases in project implementation. Welcoming the cut, the NPD's director of development and operations, Ingrid Solvberg said this was the result of oil companies and the supplier industry making "a tremendous effort in streamlining activities."

The biggest savings result from new development solutions, she said. The second largest reduction is within drilling and wells, which on average account for around 30% of the overall field development costs. This is due to the decline in rental rates for drilling rigs, and also companies are planning wells that can be drilled faster and much more cheaply per meter of depth achieved.

Pipelines and cables are also cheaper to make and new routes can be selected. Simplified development solutions and less costly materials will yield more reasonably priced modifications and adaptations of facilities where the oil and gas from new developments will be taken in and processed. But she warned against short-term savings at the expense of long-term value creation, such as cutting staff in important technical environments, as it could impair the capacity for innovation and the ability to find smart solutions.

The NPD has seen companies making false economies in the development phase, making upgrades necessary later on. "We must not put ourselves in a situation where cost cuts reduce the future flexibility on the fields, or have a detrimental impact on our ability and willingness to use technology that can provide better and more efficient resource management," says the development director.

Statoil gears up for Barents exploration

Natural Gas Europe, *31.08.2016*

Statoil aims to conduct a major exploration campaign in parts of the Barents Sea in 2017 and is looking to bolster its position there by acquiring interests from other companies, it said August 30. "We want to explore the Blamann prospect in the Goliat area, Koigen Central in PL718 on Stappen High and the Korpfjell prospect in PL859 that was awarded in the 23rd licensing round," said Jez Averty.

In addition to an exploration well in Blamann, which was awarded in January 2016 under the APA 2015 round, Statoil and Goliat operator Eni have agreed on drilling a new exploration well in Goliat in 2017.

Statoil has already a rig on contract, suitable for operation in the Barents Sea. It is also working on obtaining approval from partners and authorities for an exploration campaign in 2017 for between five and seven wells there.

During recent months Statoil has entered or increased its share in five licences in the Norwegian part of the Barents Sea by a number of agreements with Norwegian independent Point Resources, Germany-based DEA, Austria's OMV and ConocoPhillips. Statoil did not say how much of its new exploration campaign would be gas-directed; however in early August it said that it will shortly drill its first production well on the Snohvit gas field since 2007, in order to maintain feed gas supplies to its nearby onshore liquefaction complex.

Wintershall warns of 2030 EU supply gap

Bloomberg, *30.08.2016*

Lower Wintershall CEO Mario Mehren said August 30 that natural gas imports into the European Union will be remaining as important and significant, both economically and to limit global warming, as local production there declines.

He told the Offshore Northern Seas trade fair in Stavanger: "By 2030 we will already have to replace 45bn m3/yr. The dream that many people had of doing so by producing shale gas in Europe has since faded. There are many reasons for this, from questionable economic viability to political embargos. So we have to look for alternatives."

Norway, Russia and the EU itself would "form the energy triangle that balances the flows of energy for Europe and secures supply", Mehren said, with one-third of Germany's gas already coming from Norway. Producers like Norway should "make themselves more visible on the European stage in Brussels and take a clear position to ensure reliable production and a secure supply in Europe." Amid low prices, governments of producing countries too would have to create the conditions for upstream companies to continue investing, and be proactive in helping find the balance so that investments pay off, he added. BASF-owned Wintershall had increased its Norwegian production from 3,000 to over 80,000 barrels of oil equivalent in recent years.

Wintershall's Europe and Middle East upstream chief Martin Bachmann said that the Maria field, which it operates with a 50% interest offshore Norway, has 180mn boe of recoverable resources (at 100%) mostly of oil but also some gas, with start-up still planned for 2018. The company also has a 24% interest in the major Aasta Hansteen development off Norway that has 45bn m3 of recoverable gas; it is also a co-producer of gas in Russia and the UK/Netherlands with Gazprom, but has shut in production in Libya for over a year.

Seaowl aims for greater market share post Thai Ogas buy

Natural Gas Europe, *31.08.2016*

French marine security company Seaowl hopes to increase its market share within the field of oil and gas technical assistance and expand its expertise to new segments within the energy sector with the acquisition of Bangkok-based Ogas Solutions, an oil and gas services group.

This follows the company's acquisition of Wellstaff in April this year. Seaowl on August 30 said Ogas acquisition will allow the company to pursue its growth and contribute to the consolidation of the industry on an international level with an integrated services offer. Ogas has a strong footprint in Asia since the company achieves 50% of its turnover there.

"With this acquisition, our revenue will exceed €100mn ($111.61mn) in 2016, making us now a global leader in our industry," said Arnoult Gauthier, president of SeaOwl. The new group thus formed will operate on every oil and gas segment.

Poland-Slovakia link calls for bids

Natural Gas Europe, *30.08.2016*

Promoters of a planned cross-border gas interconnector, Polish Gaz System and Slovak Eustream, last week launched the binding open season for capacity in either direction. The firm bids will test the actual demand for capacity as bidders will have ship-or-pay contracts with the operator, guaranteeing it a steady stream of revenue.

The 158-km line links the Slovak-Ukraine border point of Velke Kapusany to the Strachocina compressor station in Poland. The line will be able to carry 5.7bn m³/yr from Slovakia to Poland and 4.7bn m³/yr the other way. Commissioning is expected in 2020.

Last November the European Commission defined the line as a ‘project of common interest,’ ensuring that funding is available. The sponsors argue it will ensure the diversification of sources, routes and stability of gas supplies to both countries and enhance the competitiveness of the internal gas market. Polish market participants will be able to access the so-called Southern Gas Corridor, carrying gas from production areas such as the Caspian and the eastern Mediterranean region.

Conversely, Slovak gas market participants will be able to import gas offered on the Polish market, including waterborne imports of liquefied natural gas delivered to Poland’s Baltic coast. They say overall the project will significantly increase energy security in the whole central and southern European region, including the Balkans and Ukraine, by widening the range of import options and so cutting their reliance on Russia.

Petrobras, Statoil sign MOU

Natural Gas Asia, *30.08.2016*

Statoil and Petrobras have signed a memo of understanding to strengthen their cooperation in Brazil. Petrobras and Statoil are already partners in 13 blocks at either the exploration or the production phase:

ten in Brazil and three abroad. Statoil already owns has a 60 per cent interest in the Peregrino field 85 km offshore Rio, the largest oilfield operated by Statoil outside Norway. In addition, Statoil last month agreed to buy Petrobras’ 66 per cent operated interest of the BM-S-8 license on Brazil’s offshore Santos basin for $2.5bn, subject to government approval.

Under the new MOU, the two state-led companies will evaluate joint participation in future tenders for exploration areas and increase upstream collaboration in producing fields in Brazil’s offshore Santos and Campos basins. Their agreement also sets out a potential framework for cooperation on value-creating opportunities in the gas value chain.

The MOU was signed on August 30 by Petrobras CEO Pedro Parente and his Statoil counterpart Eldar Saetre at the ONS 2016 conference in Stavanger. It will last two years and any joint activities undertaken will depend on negotiations following the signing of the document, said Statoil.

Repsol, Caixa in talks to sell 20% of Gas Natural

Natural Gas Europe, *02.09.2016*

Repsol and Spanish fund Criterio Caixa each confirmed September 1 they have been in talks with certain investors about the sale of a 20% stake in Spanish marketer Gas Natural – so 10% by each company. Both said contacts were ongoing and, once finalised, they would report back to the market.

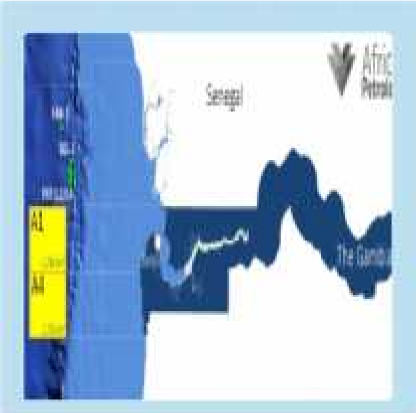
Gas Natural's principle shareholders are Criterio Caixa 34.4%, Repsol 30% and Algerian state gas and oil producer Sonatrach 4%. Criterio and Repsol effectively share joint control of the Spanish gas marketer, although this would no longer be the case if each divested 10% equity.

Criterio Caixa is the investment company that manages mutually-owned Catalan savings bank La Caixa's industrial holdings.Spanish business newspapers Cinco Dias and Expansion reported that Global Infrastructure Partners was tipped as the likeliest buyer. Kohlberg Kravis Partners had also expressed interest, reported Cinco Dias. The 20% package could be worth some €4bn, it was reported.

Gas Natural shares ended the day 3% higher at €19.07/share, putting its current market capitalisation at some €19bn. In contrast Spain's Ibex-35 index of leading companies was little changed. International funds have invested in subsidiaries of Gas Natural before. In March 2015 Gas Natural brought in state Kuwait Investment Authority-owned Wren House as a 25% partner in 'Global Power Generation', its subsidiary for non-Iberian generation assets with 2.9 GW of installed capacity.

Gambia explorer claims farm-in interest

Natural Gas Europe, *31.08.2016*



Statoil A small Australia and Oslo-listed, but London-based independent present offshore Gambia says it has signed a letter of intent (LOI) to farm out part of its 100% interest in the country's offshore deepwater licences A1 and A4. However, its current licence period is set to expire September 1 2016.

APC said August 31 it signed the LOI with "an undisclosed international E&P company" and that it represents a non-binding commercial proposal about the "possible acquisition of interests" in the two blocks. However, it said the LOI is conditional on APC confirming an extension of its exploration period by at least 12 months from the Gambian government.

Licence A1 borders two of the three offshore northern Senegal licences where UK independent Cairn Energy, now working with Woodside, has recently discovered significant oil and gas volumes. Since 2012 Houston-based Erin Energy has held Gambian offshore licences A2 and A5, which are adjacent to APC's blocks. Gambia also has two shallow water blocks A3 and A6 near to its coast, believed to be open. It has been little explored, but lies sandwiched between northern and southern Senegalese waters which lately have attracted more exploration.

When A1 and A4 were reinstated by Gambia in 2014 with APC after a dispute, it undertook to drill at least one exploration well and conduct 3D seismic on part of its acreage. Its website confirms that it conducted a major 3D seismic survey covering 2,500km². A spokesman confirmed that it has yet to drill a well. As at August 31, APC – which has no connection to Lundin-owned Africa Oil Corporation – said it had ten licences in five West African countries.

Sinopec's H1 profit declines 22%

Natural Gas Europe, *29.08.2016*

Sinopec has reported a 21.6% drop in net profit for the six months that ended on June 30 as international oil and natural gas prices remained low.

For the first six months of 2016, company's net profit was yuan 19.9 bn. Sinopec's total turnover was yuan 879.22bn it said August 28. In the first half of 2016, the operating profit was yuan 35.1bn, down 13.3% on the previous year. Sinopec's results were only a tad better than those of two other Chinese state owned energy firms PetroChina and Cnooc who respectively reported a 98% decline in half-year profit; and its first H1 loss in more than a decade.

Production in the first half of 2016 was 218.99mn barrels of oil equivalent. Domestic crude production was 128.38mn barrels while overseas production was 25.79mn barrels, and total gas production was 388.69bn ft^3.

Sinopec said it will press ahead with development of Fuling shale gas field in the second half of the year as well as speed up key capacity building projects, optimise production and sales, and intensify reservoir assessment in west Sichuan and northeast China.

In the second half of 2016, it plans to produce 147mn barrels of crude oil, of which domestic production will account for 125mn barrels and overseas production will account for 22mn barrels. Natural gas production is expected to be 421.2bn ft^3 during the period.

The company expects oversupply conditions in global oil market to continue in the second half of the year. "China's economic growth is expected to be steady in the second half of 2016, which will drive the growth of domestic demand for refined oil products and petrochemical products. The consumption mix of oil products shall continue to change, and demand for chemical products shall be gradually going for more high-end products. Yet over-supply in the international oil market is likely to persist, and international oil prices will stay at a low level," it said.

Malaysian coastal bullish on Indonesian LNG

Natural Gas Asia, *30.08.2016*

Malaysian offshore support vessels fabricator Coastal Contracts sees robust growth in Indonesia's LNG regasification and storage services market and is optimistic about its entry into that fast growing sector, the company said.

On July 30, Coastal Contracts announced its entry into the Indonesian LNG supply chain with the signing of a MoU to buy a 49% stake in Jaya Samudra Karunia Gas (JSK Gas) for ringgit 27mn ($6.6mn). JSK's key business segments include dry bulk shipping, transshipment, gas, mining and valves manufacturing.

In recent years, given the huge potential in Indonesia LNG market, JSK has ventured into the LNG supply chain. Recently, it was awarded the LNG re-gasification and storage contracts to support a gas-fired power plant in Bali, Indonesia. Following the successful completion of the deal, Coastal Contracts would have joint control over JSK Gas's operating subsidiaries and assets. JSK Gas, through its 99% owned subsidiary Benoa Gas Terminal (BGT), would be engaged in the operations and transfer of a floating LNG regasification unit over a five-year contract period. Meanwhile, for the three months that ended on June 30, its revenue rose to ringgit 200.8mn, up 22.4% on previous year. Net profit stood at ringgit 12.9mn, down 63% from a year ago period.

Indonesian Tangguh project to supply 15 LNG cargoes to Arun terminal in 2016

Natural Gas Europe, *31.08.2016*

Malaysian Indonesia's Arun LNG import terminal will receive 15 LNG cargoes from the Tangguh project during 2016. Seven cargos have already been supplied during the first half of the year, SKKMigas' head of public relations Taslim Z. Yunus said adding that PT PLN (Persero) is the only recipient of LNG through Arun regasification facilities.

The average price of Tangguh LNG supplied to Arun has been \$4.9/mn Btu for the first six months of the year down from \$6.74/mn Btu for the same period last year. "This price includes the costs of exploration, exploitation, LNG liquefaction, and transportation distances of up to 4,800 km,"

In July, BP and its partners approved the final investment decision (FID) to expand Tangguh LNG by adding a third train (Train 3) and 3.8mn mt/yr of production capacity, bringing total plant capacity to 11.4 mn mt/yr. The project also includes two offshore platforms, 13 new production wells, an expanded LNG loading facility, and supporting infrastructure, BP said. Sources said that with falling costs in the industry the project was now put at the lower end of the \$8bn-\$10bn range.

BP said about 75% of the Train 3 annual LNG production has been sold to the Indonesian state electricity company PT. PLN (Persero). The remaining volumes are under contract to Kansai Electric Power Company in Japan, the other foundation buyer for Train 3.

Turkmenistan lobbies Germany on gas

Natural Gas Europe, *31.08.2016*

When Turkmenistan's President Gurbanguly Berdimukhammedov held talks in Berlin this week, there was one major energy subject on his mind: how to find a way to get Turkmen gas flowing to European markets.

It's a subject that has exercised Turkmen and EU officials for more than a decade, but it really does seem as if, finally, Turkmenistan's leader is trying to break the log-jam. But he faces a tough task. The problem is that what Brussels and Ashgabat have long wished to achieve – the development of a system that could carry as much as 30-40bn m³/yr of Turkmen gas to European markets.

This amount is simply not attainable under current conditions, not least since it would require the installation of major new infrastructure costing tens of billions of dollars to connect Turkmenistan production with core consumption in western Europe. It would also antagonize Moscow, since it would pose a major commercial challenge to Russian gas on European markets.

What might be achievable, however, is a much more modest programme that would enable gas from Turkmenistan's Caspian fields to access Azerbaijan's existing domestic and export systems by means of a link between existing offshore facilities in the two countries.

"We in Turkmenistan are interested in delivering our energy resources to the West," Berdymukhammedov said during a joint press conference with German Chancellor Angela Merkel August 29. More importantly, he added that the Turkmen government had presented the European Commission with proposals for how to proceed and that Turkmenistan and the European Commission were jointly working on legal and technical issues.

This, in itself, constitutes a significant step forward. As one commercial source commented to NGW in Baku, in previous discussions with the European Commission, Turkmenistan "didn't commit, didn't reject" EU efforts to break the log-jam. At present, China is the only cash destination for Turkmen gas exports. Last year Turkmenistan did sell 7.2bn m^3 to Iran, as well as 27.7bn m^3/yr to China, but the Iranian sales were largely conducted as barter. Since Russia ceased to purchase Turkmen gas last year – and purchase may not be quite the right word, as the Turkmens say Gazprom did not pay them for the 2.8 bcm of gas they supplied – Ashgabat has no alternative market to help it become a price maker, rather than a price taker.

In an ideal world it would like to sell its gas to India and Pakistan. In commercial terms, this would make a lot of sense which is why Ashgabat has pursued the project of a Turkmenistan-Afghanistan-Pakistan-India (TAPI) pipeline so assiduously for close to 20 years. In this context, Berdymukhammedov's visit to Berlin may constitute an acknowledgement that henceforth the focus has to be on getting Turkmen gas to Europe, because, under current security conditions in Afghanistan, it is simply impossible to raise the kind of finance needed to develop TAPI, a project estimated to cost in excess of $10bn for a 1,680-km, 33bn m^3/yr system.

In the last two years there have been intense efforts by Azerbaijan to see whether Turkmenistan would be interested in a relatively modest connection between the two states, whose coasts on either side of the Caspian are less than 300 km apart. Commercial sources in Baku say both Baku and Ashgabat are seriously exploring the possibility of a connection between Turkmenistan and Azerbaijan's offshore installations but add that while these discussions have borne some fruit, there are still obstacles to be overcome.

One of these was mentioned by state Socar's first vice president Khoshbakht Yusifzade when he told a conference in Baku August 30 that Turkmenistan stood to benefit from a connection to Azerbaijan's pipeline infrastructure. "We have pipelines stretching to the middle of the Caspian Sea which are at a small distance from Turkmenistan," Yusifzade said. However, he also raised the issue of a disputed oilfield in the centre of the Caspian, known to Azerbaijan as Kyapaz and to Turkmenistan as Serdar. "There is also an issue connected with the development of Kyapaz border field," Yusifzade said. However, he added, "I think that we will resolve this issue in the near future."

Other core issues that would need to be resolved concern financing for the project and the volumes that it might carry. One commercial source asked the key question, to which as yet there is no answer: “Who will take the commercial burden, who will invest?”

More broadly, there is an expectation that were an agreement to be concluded on a tie-up pipeline, the volumes it would carry would be in the order of eight to 12bn m^3/yr. That would enable some gas to be used by Azerbaijan, which is short of gas for domestic customers as its principal gas production at Shah Deniz is earmarked for export, and for some gas to be dispatched westwards to Turkey and possibly further afield by means of the €39bn Southern Gas Corridor system now under development.

Any substantial modification of inputs at the Azerbaijani end to the SGC would need new pipe to be laid in Georgia, but SGC officials have said previously that this would pose no problem so long as they were given proper notice. Petronas is producing some 5bn m^3/yr at Block One, of which around 4bn m^3/y are exported to Iran. But the Malaysian operator possesses the ability to ramp up production to around 10bn m^3/y within a couple of years, while gas from the nearby offshore field being developed by the UAE’s Dragon Oil, together with some nearby onshore production by the ENI-owned Burren Energy, could allow for as much as 12bn m^3/yr of Turkmen Caspian region gas to be delivered to Azerbaijan without too much cost or effort.

If there was to be a tie-up between Turkmenistan’s offshore Block One, which is operated by Malaysia’s Petronas Carigali, it would not be plugged into the gas gathering system at Azerbaijan’s Shah Deniz gasfield, where Petronas is also a shareholder, but to the gas gathering system attached to Azerbaijan’s giant offshore Azeri-Chirag-Guneshli oilfield complex. This could potentially reduce the connection span to little more than 100 kms. Even developing a Turkmenistan-Azerbaijan field connector will not be easy. But if such a system were to be develop, it would enable at least some Turkmen gas to enter European markets.

Turkmenistan and Azerbaijan will need partners to ensure such a development. That’s why Berdymukhammedov has been visiting Berlin, and that’s why he said at the August 29 press conference that “we believe that Germany as a respected and authoritative member of the European Union will further provide support to this process.” As for the German Chancellor’s own thoughts on the matter, she commented simply at the press conference: “I hope the problems that still exist can be overcome.”

BP, CNPC sign 2nd shale gas deal

Natural Gas Europe, *01.09.2016*

Malaysian BP has signed a second production-sharing contract for shale gas exploration, development and production with China National Petroleum Corporation, the UK major said September 1.

Signed on July 27, the production-sharing contract (PSC) covers some 1,000 km² at Rong Chang Bei in the Sichuan Basin. In March 2016, BP and China National Petroleum Corporation signed their first shale gas PSC on the adjoining Neijiang-Dazu block. As with the earlier contract, China National Petroleum Corporation (CNPC) will operate the Rong Chang Bei PSC.

BP CEO Bob Dudley said: “Combining CNPC’s operational expertise with BP’s technology and experience, we now expect to leverage the synergies between these blocks. This new PSC clearly demonstrates our continued commitment to invest in projects in China which will deliver long-term value to BP, to our Chinese partners and, most importantly, to the country.”

BP and CNPC signed their framework agreement on strategic cooperation in October 2015 when the Chinese president, Xi Jinping, visited the UK. In addition to unconventional resources, that agreement covers possible future fuel retailing ventures in China, potential new oil and LNG trading opportunities globally and carbon trading, as well as sharing low carbon energy knowledge. CNPC chairman Wang Yilin said that the two unconventional resource PSCs signed this year are a “manifestation of our deepening cooperation.”

BP’s 2016 Energy Outlook forecast that, by 2035, shale gas would account for one-quarter of world gas production and China will become the world’s largest contributor to shale gas production growth. “China is important for global energy markets and for all BP’s businesses. With this new PSC sealed, we want to further expand our presence in this vital market,” said Edward Yang, BP China President.

Australian awe commences gas sales from Waitsia project

Reuters, *29.08.2016*

Saudi Australian AWE has started commercial gas sales from stage 1A of the Waitsia project in Perth Basin. The project was on time and with the approved budget of A$18mn.

The project is operated by AWE, with 50% interest, and in production licence L1/L2 in the onshore Perth Basin. Stage 1A comprised the installation of new infrastructure to connect the Waitsia-1 and Senecio-3 gas wells to the upgraded Xyris production facility. The gas is being delivered to the Parmelia pipeline with Alinta Energy taking up to a maximum daily quantity of 9.6 TJ/day under a 2.5 year take or pay gas sales agreement.

AWE said it is now focused on moving towards stage 2, a full field development phase that would increase production capacity up to 100 TJ/d. The development concept selection process for Waitsia stage 2 has begun and two new appraisal/production wells are planned to be drilled in calendar year 2017.

Beach energy reports second consecutive full-year loss

Natural Gas Europe, *29.08.2016*

Australian Beach Energy has reported a net loss for the second straight year. On August 29 the company said its net loss for the year that ended on June 30 stood at A$589mn compared with A$514mn reported in the previous year. Total revenue weakened 23% to $558m impacted by low oil prices.

Production during the year was 9.7mn barrels of oil equivalent. Oil accounted for 53% and gas and gas liquids for 47% of its output. Total oil production was 5.2mn barrels, up 12% on last year thanks to successful completion of the merger with Drillsearch, new wells brought online and various field development projects.

Gas and gas liquids production was 4.5mn boe, down 1%. Beach said its merger with Drillsearch provided full ownership of key Western Flank oil and gas permits, additional gas and gas liquids exploration acreage, and expected annual pre-tax cost savings of up to A$40mn. The average realised oil price decreased to A$60/b, down A$30/b from the previous year.

In the fiscal year 2017, production is likely to be higher than what was achieved in FY16, with guidance in the range of 9.7mn to 10.3mn boe, Beach said.

Australian Victoria state permanently bans fracking

Natural Gas Asia, *30.08.2016*

Australian state of Victoria has permanently banned exploration and development of all onshore unconventional gas, including hydraulic fracturing and coal seam gas.

In a statement released August 30, the Labor government said the permanent legislative ban, a first for Australia, to be introduced to parliament later this year, will protect the "clean, green" reputation of Victoria's agriculture sector, which employs more than 190,000 people. "The government's decision is based on the best available evidence and acknowledges that the risks involved outweigh any potential benefits to Victoria."

The state has imposed a moratorium on fracking since August 2012. Exemptions to the ban will remain for other types of activities that are not covered by the current moratorium, such as gas storage, carbon storage research and accessing offshore resources, the government said adding that exploration and development for offshore gas will also continue.

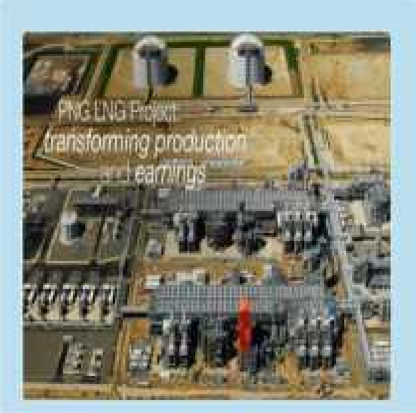
The government will also legislate to extend the current moratorium on the exploration and development of conventional onshore gas until June 30, 2020. Australia's key oil and gas industry body, the Australian Petroleum Production and Exploration Association (APPEA) has been extremely critical of Victorian government's approach towards the natural gas industry.

"All credible, independent inquiries have confirmed that, properly regulated, the natural gas industry is safe. Political decisions should be based on facts, not dishonest fear campaigns. More than any other state, Victoria relies on natural gas. Almost 80% of homes use natural gas. Natural gas is also the invisible ingredient for manufacturing – 27% of the gas consumed by industry in Victoria is used as feedstock to make essential products such as glass, bricks and fertilisers. There is no substitute," APPEA chief executive Malcolm Roberts said August 15.

There has been stiff resistance to coal seam gas exploration in some Australian states mainly on environmental grounds. New South Wales has seen widespread protests at exploration sites. In the last couple of years, the government has bought back and cancelled many permits.

PNG focused oil search ups 2016 production guidance

Natural Gas Europe, *29.08.2016*



Papua New Guinea-focused Oil Search last week upped its 2016 full year production guidance to 28-30mn barrels of oil equivalent. In April, it guided for 27.5-29.5mn boe. Total production in the first half of 2016 was 14.9mn boe, the second highest half-year in company's history while sales volumes rose 5% to 15.2mn boe the company said on August 23 while announcing its results for the six months.

The string of poor results continues for Australia listed energy firms as Oil Search too has reported poor results. Its net profit of A$25.6mn (US$19.3mn) was down 89% from the same period of last year.

Total revenue fell 33% to $580.8mn as realised prices for oil and condensate slumped 27% and prices for its gas and LNG product fell 40%. It managed to cut production costs by 8%. Performance from the PNG LNG project was very strong, averaging 7.7mn mt/yr during the first half, 12% above the nameplate capacity of 6.9mn mt/yr. During the first half of 2016, 53 LNG cargoes were sold, comprising 45 sold under long-term contracts and eight sold on the spot market. Six of the eight spot cargoes were sold to customers in Japan.

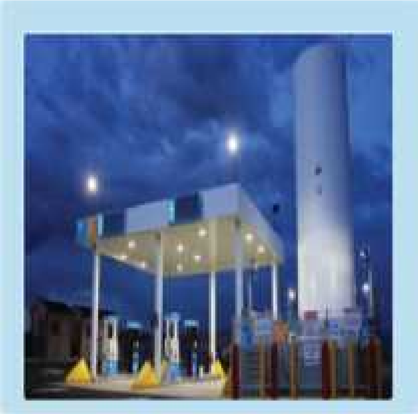
Last month, Oil Search withdrew its bid to buy InterOil after it was trumped by ExxonMobil. InterOil on July 18 announced that ExxonMobil had offered a 'superior proposal'. In May, InterOil entered into an agreement to be acquired by Oil Search for $2.2bn, with Oil Search to sell about 60% to Total for $1.2bn. Under the arrangement agreement between Oil Search and InterOil, Oil Search had the opportunity to submit a revised offer before or after any agreement is entered into by Interoil and ExxonMobil.

"Following a detailed review of the ExxonMobil proposal, including an analysis of the recent Elk-Antelope resource certification, the value and opportunities offered by cooperation between Papua LNG and PNG LNG and the likelihood of realising this value by having ExxonMobil in the Papua LNG Joint Venture, the Oil Search Board has decided it is not in the best interests of shareholders to submit a revised offer for InterOil," Oil Search said last month. Exxon will pay more than $2.5bn for InterOil.

Oil Search has interests in two PNG based LNG projects: ExxonMobil operated PNG LNG project, which is due for expansion, and Total operated Papua LNG project, which is based on development of the Elk-Antelope gas fields in PRL 15. InterOil too has a 36.5% stake in Papua LNG project.

Chevron, ENN sign LNG agreement

Natural Gas Europe, *30.08.2016*



US major Chevron has signed a binding LNG sale purchase agreement with ENN LNG Trading Company for the delivery of the fuel to China from its global supply portfolio. In a statement August 29, the company said the Chinese gas distributor would receive 0.65mn metric tons (mt)/yr of LNG over 10 years, with the first delivery expected to start in 2018 or the first half of 2019.

One of China's biggest gas distributors, ENN operates in 150 cities across 17 provinces and autonomous regions, with over 12mn residential and 56,000 industrial/commercial customers.

ENN's Zhoushan LNG receiving terminal is being constructed and expected to be in operation by 2018. Gas demand growth has been robust in China this year driven by November's price cut. ENN reported a 17% rise in volumes for the half year that ended on June 30. During the six months, its total natural gas sales volume was 6.48bn m^3. Residential gas sales volume increased by a robust 23%. Higher supplies of LNG drove a significant year-on-year volume growth of 95.9% to 1.02bn m^3. It projects a 15% growth in gas sales volume for fiscal year 2016. With the kind of volume growth seen in the first half, the company is likely to beat its own target.

Announcements & Reports

► *Not All Oil Supply Shocks Are Alike Either: Disentangling The Supply Determinant*

Source : OIES
Weblink : https://www.oxfordenergy.org/wpcms/wp-content/uploads/2016/08/Not-all-oil-shocks-are-alike-either-Disentangling-the-supply-determinant.pdf

► *Turkish Stream Back on The Agenda?*

Source : EPC
Weblink : http://www.epc.eu/pub_details.php?cat_id=4&pub_id=6903

► *Natural Gas Weekly Update*

Source : EIA
Weblink : http://www.eia.gov/naturalgas/weekly/

► *This Week in Petroleum*

Source : EIA
Weblink : http://www.eia.gov/petroleum/weekly/

Upcoming Events

► *FSRU Asia Summit*

Date : 06 – 07 September 2016
Place : Amara Sanctuary Resort Sentosa, Singapore
Website : http://www.fsrusummit.com/

► *23rd Annual India Oil & Gas Review Summit & International Exhibition*

Date : 09 – 10 September 2016
Place : Mumbai, India
Website : www.oilgas-events.com/india-oil-gas/

► *Rio Oil & Gas Expo & Conference*

Date : 14 – 16 September 2016
Place : Rio de Janeiro, Brazil
Website : https://www.whereinfair.com/rio-oil-gas-expo/rio-de-janeiro/2016-Sep/

► *Operational Excellence in Oil and Gas Europe*

Date : 19 – 21 September 2016
Place : London, UK
Website : http://www.opexinoilandgasemea.com/

► *Iran International Petroleum Congress (IIPC)*

Date : 19 – 21 September 2016
Place : Tehran, Iran
Website : www.iranpetroleumcongress.com/

► *2016 Deloitte Oil & Gas Conference*

Date : 21 September 2016
Place : Houston, USA
Website : www2.deloitte.com/us/en/pages/energy-and-resources/events/oil-and-gas-conference.html

► *Global Oil & Gas - Black Sea and Mediterranean*

Date : 22 – 23 September 2016
Place : Athens, Greece
Website : www.iene.eu

► *Global Oil & Gas South East Europe & Mediterranean Conference*

Date : 28 – 29 September 2016
Place : Athens, Greece
Website : www.oilgas-events.com/Global-Oil-Gas-Black-Sea-Mediterranean-Conference/

► *Kazakhstan International Oil & Gas Conference (KIOGE) 2016*

Date : 05 October 2016
Place : Almaty, Kazakhstan
Website : www.kioge.kz/en/conference/about-conference+

► *23rd World Energy Congress*

Date : 09 - 13 October 2016
Place : Istanbul, Turkey
Website : http://wec2016istanbul.org.tr/

► *International Conference on Oil Reserves & Production*

Date : 17 - 18 October 2016
Place : London, UK
Website : www.waset.org/conference/2016/10/london/ICORP

► 15th ERRA Energy Investment & Regulation Conference

Date : 17 - 18 October 2016
Place : Budapest, Hungary
Website : http://erranet.org/InvestmentConferences/2016

► The 8th Saudi Arabia International Oil & Gas Exhibition (SAOGE)

Date : 17 - 19 October 2016
Place : Dammam, Saudi Arabia
Website : www.saoge.org

► 21st IENE National Conference "Energy and Development 2016"

Date : 24 - 25 October 2016
Place : Athens, Greece
Website : www.iene.eu

► SPE Russian Petroleum Technology Conference & Exhibition

Date : 24 - 26 October 2016
Place : Moscow, Russia
Website : www.spe.org/events/rpc/2016/

► Asia Pacific Oil & Gas Conference & Exhibition (APOGCE)

Date : 25 - 27 October 2016
Place : Perth, Australia
Website : www.spe.org/events/apogce/2016/

► International Conference & Expo on Oil & Gas

Date : 27 - 28 October 2016
Place : Rome, Italy
Website : www.oil-gas.conferenceseries.com/

► 4th Iran Europe Oil & Gas Summit

Date : 01 – 03 November 2016
Place : Berlin, Germany
Website : www.iransummit.com/

► 2nd International Conference & Expo on Oil & Gas

Date : 02 – 03 November 2016
Place : Istanbul, Turkey
Website : www.oil-gas.omicsgroup.com/

► *European Autumn Gas Conference 2016*

Date : 15 – 17 November 2016
Place : Hague, Netherlands
Website : http://www.theeagc.com/

► *21st Annual Oil & Gas of Turkmenistan (OGT) Conference 2016*

Date : 16 – 17 November 2016
Place : Ashgabat, Turkmenistan
Website : http://www.ogt.theenergyexchange.co.uk/

► *Project Financing in Oil & Gas*

Date : 21 – 22 November 2016
Place : London, UK
Website : www.smi-online.co.uk/energy/uk/conference/Project-Financing-in-Oil-and-Gas

► *5th Greek Greek Cyprus Energy Symposium*

Date : 29 - 30 November 2016
Place : Nicosia, Greek Greek Cyprus
Website : www.iene.eu