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EU South Stream Thaw?

The European Commission certainly hasn't learned to love the Gazprom-led South Stream project that would bypass Ukraine to bring Russian gas directly to Europe under the Black Sea. Nor has it shown any inclination to grant Gazprom the exemption it so desperately wants for the project from EU third-party access requirements.

But officials including Russian Energy Minister Sergei Shmatko and other Russian analysts took some heart from the fact that European Energy Commissioner Gunther Oettinger said at a high-level Russian presentation on the project in Brussels last week that the EU will "support South Stream in its administrative processes in the EU, and we will not impose any unreasonable or unjustified level of administrative or regulatory requirements."

The delegation making the case for South Stream included not only Shmatko but also Gazprom chief Alexei Miller, Gazprom Export head Alexander Medvedev, South Stream boss Marcel Kramer and Eni CEO Paolo Scaroni. Eni is currently a 50-50 partner with Gazprom in the company set up to build the subsea section of the planned 63 billion cubic meter per year (6 billion cubic foot per day) line (WGI Mar.23,p4).

Shmatko said after the meeting that Oettinger behaved as an "ally — something that has not happened for quite some time." Analysts that this was the first time the commission had said that the EU would not create obstacles for South Stream. Oettinger stated explicitly that South Stream is not "our top priority," but he conceded, "we recognize its value, in particular for Russia, for diversification of routes." Questions that he put to Russian participants, rhetorically at least, included whether companies other than Gazprom would be able to use the system and whether it would divert gas from Ukraine.

Like Oettinger, Pierre Morel, EU special representative for Central Asia, said that if South Stream lands in Europe, it has to live according to European rules, including the EU Third Energy Package requirements for third-party access and separation of infrastructure ownership from gas marketing. However, some Moscow-based observers expect the EU to now grant some concessions to South Stream, given disruptions to Libyan gas supply and a slide in Nabucco's targeted completion date to 2017 (p2).

Sebastian Sass, head of EU and regulatory affairs for South Stream, told the CIS Oil and Gas Summit in Paris last week that the process of regulatory clarification is underway, and that how European regulatory demands will influence the project will become clearer once an integrated feasibility study is finished next year. Sass effectively answered one of Oettinger's questions: One-third of the capacity would be for new gas, implying that two-thirds would be diverted from Ukraine. South Stream will be profitable if the more than \$2 billion lost during the 2009 Ukrainian transit crisis and increasing transit costs in Ukraine of \$2.75 bil-
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China Set for More Gas-Fired Power

This summer's much-discussed power shortage in China has sharply highlighted the importance of diversifying fuel sources in the country's coal-heavy generation sector. Partly as a result, natural gas could join hydropower and nuclear in seeing significant short-term growth in this vital sector.

Besides a cutback in imports due to the high cost of coal on world markets, the power shortage also results in part from the fact that central China is suffering one of its worst droughts in 50 years, with average rainfall in some provinces at record lows (WGI May25,p9). Hydropower typically makes up about 20% of electricity output in peak months, but not this year — adding to the country's electricity woes.

To ease the current power crunch, the government has raised electricity tariffs in hopes of encouraging generators to increase utilization rates. Several provinces raised tariffs in April by 1.2 yuan (18.5¢) per kilowatt hour, and more hikes could come if the situation worsens.

However, the magnitude of tariff increases will be constrained by the National Development and Reform Commission's (NDRC) desire to battle strong inflationary pressures in the economy.

The crux of the problem is that electricity price increases have not kept pace with coal price rises, leaving about 80% of China's coal-fired facilities

(See China, page 2)

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lion are taken into account, he added. Financing is planned through syndicated loans, and the schedule to start flows in 2015 “is ambitious but not unusual.”

Moscow has for nearly two years been seeking Trans-European Network (Ten-E) status for South Stream, which would exempt it from EU Third Energy Package third-party access and unbundling requirements, in force since March. Ten-E status would also give the South Stream consortium access to soft loans and fast-track planning decisions.

Brussels has already awarded such status to the Gazprom-led Nord Stream project, which will soon be flowing Russian gas under the Baltic (WGI May25,p2).

Oettinger gave a strong hint as to what Moscow could do to get active support from Brussels: “If South Stream for example gives access to gas independents active in Russia, then South Stream would deliver on two essential criteria: namely diversification of routes and counter-parties. That means a stronger contribution to European diversification efforts.”

However, observers say, it’s unlikely Moscow will be willing to break Gazprom’s gas export monopoly — even for independents as powerful as Novatek (WGI May18,p3).

In an apparent bid to win support from Brussels by other means, Gazprom has said it is considering inviting E.ON Ruhrgas to join the project, and a representative of the German company attended the presentation. France’s EDF is already set to join with a stake of at least 10%, while Germany’s BASF recently agreed to take 15%. Both will acquire their interests from Eni.

A final investment decision is due on South Stream next year, with gas flows scheduled to start at 15 Bcm-20 Bcm in 2015, increasing to 63 Bcm/yr by 2019-20. Total project costs are put at 15.5 billion rubles (\$21.8 million), including an estimated 10 billion rubles for the subsea stretch.

(China, continued from page 1)

running at a loss. Goldman Sachs estimates that coal prices have risen 74% since end-2006, while tariffs for independent power producers increased only 11% over that same period.

Gas-fired power has in the past not been popular with the generation sector because of poor economics. Gas has historically been more expensive than coal, giving producers little incentive to switch to gas-fired facilities. Many such plants were built and encouraged by provincial governments when LNG receiving terminals in Guangdong, Fujian and Shanghai were planned.

Power producers in Guangdong province are unhappy over a recent price adjustment by the provincial government. In March, Guangdong reduced the tariff for regasified LNG-fed power plants from 0.571 yuan/kwh (9¢/kwh) to 0.533 yuan/kwh, with the rationale that these plants have enjoyed profit margins of about 20% because term gas is bought cheaply — for roughly \$3.30 per million Btu ex-ship — from the North West Shelf project in Australia via China National Offshore Oil Corp.’s Guangdong Dapeng LNG.

But the terminal also imports from Qatar and occasionally takes in more expensive spot cargoes (WGI Oct.13,p6). Illustrating the mix, the Pearl River LNG power plant owned by Guangzhou

Development Industry relies on North West Shelf gas to supply 60% of the gas for its 780 megawatt plant and has to procure the rest from spot volumes. The average ex-ship price paid by China for LNG in the first quarter was \$7.29/MMBtu (WGI May11,p6).

Besides price, the other sticking point has been that gas supply often goes to city gas, residential and industrial users first as a matter of priority, leaving the power sector short. A few power-generation firms that have experimented with gas-fired power plants report that their plants have been running at low rates, if at all, because of difficulty in getting gas.

Although coal will still dominate China’s energy mix, gas is poised to become increasingly significant in the next five years because of Beijing’s emphasis on clean energy in the current five-year economic plan (WGI Mar.30,p9). The government also expects gas supply to grow significantly over the next few years, underpinning the more bullish views on demand going forward (WGI May5’10,p1).

Wood Mackenzie estimates that gas-fired power generation will increase from 50 terawatt hours last year to 131 TWh in 2015. However, this is still only a fraction of total generation: Last year, China generated about 4,141 TWh.

Nabucco Still Waiting on Elusive Supply

While a bit of fanfare will doubtless accompany the signing in Turkey next week of project-support agreements — the next stage in the planned 31 billion cubic meter per year (3 billion cubic foot per day) Nabucco pipeline — real progress remains thin on the ground.

Lack of supply continues to dog backers of the OMV-led project, some nine years after the pipeline was first proposed. The Nabucco consortium last month pushed construction start-up back

a year to 2013 “to align the Nabucco timeline with gas suppliers.” First flows are now envisaged in 2017.

Azerbaijan’s Socar, the most obvious candidate for first-phase Nabucco volumes with gas to come from Phase 2 of its Shah Deniz development, continues to sit on the fence, saying it will consider all contenders vying to transport its gas to Europe. Besides Nabucco, this takes in the smaller Interconnector-Turkey-Greece-Italy (ITGI) and the Trans-

Adriatic Pipeline (TAP) (WGI May4,p4).

The five project-support agreements to be signed Jun. 8 — one for each Nabucco transit country — will effectively bring the intergovernmental agreement struck in July 2009 down to national level, affirming freedom of transit and protection from discriminatory changes in law and setting standards for land acquisition, according to Nabucco spokesman Christian Dolezal (WGI Mar.10'10,p2).

The Nabucco partners are Austria's OMV, Hungary's Mol, Germany's RWE, Bulgaria's Bulgargaz, Romania's Transgaz and Turkey's Botas.

But in the long interim since Nabucco was first conceived, Turkey's ambivalence about the project appears to have grown (WGI Mar.23,p10). Energy Minister Taner Yildiz in mid-May expressed his frustration at the lack of progress, telling CNN Turk: "I think it is high time the candidate suppliers present their preferences on the matter. Even 'no' is an acceptable answer."

Later in the month, Yildiz indicated that Turkey on Jun. 8 would be pressing Azerbaijan for its position on gas supply, saying that if Azerbaijan said no, "then we will address Turkmenistan, Iraq and Iran." But a senior Botas official in March warned that securing gas from those sources did not seem possible in the short-term.

Last week's energy-partnership deal between the EU and Iraq — in which Iraq agreed to supply gas to Europe via the Southern Corridor and the EU agreed to guarantee a market — is a positive step. But Iraqi Deputy Prime Minister for Energy Hussein al-Shahristani in early April indicated that exports would not begin in the near future given Iraq's own gas needs, and would not necessarily arrive via Nabucco (WGI May4,p1).

Nabucco is more directly targeting gas exports from Iraq's Kurdistan region, and here an initial payment in May by the federal government in Baghdad to the Kurdistan Regional Government (KRG) to cover oil firms' upstream costs offers some promise: The KRG, often at odds with Baghdad over energy policies, will need federal go-ahead for any future gas exports.

Even one of Nabucco's biggest backers — the EU — is showing signs of fatigue. Energy Commissioner Gunther

Oettinger told Germany's *Die Zeit* in May that it is not easy "to convince banks and investors that the project makes sense," further warning that "all big projects can fail."

Oettinger last month also told a conference in Stuttgart that Nabucco costs had risen to €12 billion-€15 billion (\$17 billion-\$21.4 billion), from the €7.9 billion estimate based on a 2005 feasibility study. Nabucco says it is currently reviewing its calculation of the €7.9 billion capex figure to reflect market developments.

Jordan Pushes LNG Plans Forward

Jordan could see its first LNG imports within five years, an official at the energy-short country's National Electric Power Co. said this week. "We expect to start utilizing [LNG] by 2015 to 2016," Bahjat Aulimat, head of planning for electricity generation at Nepco said on the sidelines of a conference in Dubai.

Officials in Jordan, which relies heavily on pipeline gas imported from Egypt, have been considering LNG for months, but the decision to push forward came after two explosions on the Sinai Peninsula disrupted flows through the Arab Gas Pipeline this year amid unrest in Egypt (WGI May11,p1). Israel is hoping to develop 1 billion-1.5 billion cubic meters per year of LNG import capability as soon as 2012 in response to

similar disruptions in its gas flows from Egypt (WGI May25,p3).

Jordan is studying importing 1 Bcm/yr (740,000 tons/yr) of LNG at the port of the Gulf of Aqaba north of the Red Sea, a volume that would likely serve only to cover existing gas needs rather than meet new demand. Jordan is simultaneously searching for ways to increase its power-generation capacity from three gigawatts to 5 GW by 2020, but is eyeing nuclear and shale oil for that purpose, rather than gas.

Egyptian pipeline exports have yet to resume after an attack in April halted gas flows for the second time this year. Jordan's King Abdullah visited Egypt last week, in part to address his country's concerns over gas supply.

Aulimat said the Egyptians are not trying to renegotiate the price at which they send gas to Jordan. However, Cairo is trying to revisit the price for its gas sales to Israel, where gas flows from Egypt have yet to resume either. This week US firms with stakes in the East Mediterranean Gas pipeline supplying Egyptian gas to Israel said they would be seeking arbitration under the US-Egypt bilateral treaty.

Meanwhile, Jordan is negotiating a power purchase agreement with Estonia's Eesti Energia that would see a 750 megawatt shale oil-fired power station brought on line in three phases in 2016. "By the end of this year we will sign all of the agreements related to this project, including the power purchase agreement," Aulimat said.

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The oil shale is cheaper than the fuel oil Jordan is currently substituting for Egyptian gas but more expensive than natural gas, he added.

The country expects to float a tender for its nuclear power station in July, despite several setbacks to plans for a 1 GW plant. Citing potential diplomatic and financial complications, the Jordan Atomic Energy Commission changed the site from the Gulf of Aqaba to a location 50-60 kilometers north of Amman.

Jordan had also hoped to develop its uranium deposits to help defray the high cost of a plant, but Rio Tinto pulled out of the country after failing to discover commercial quantities of the fuel. A separate exploration program by France's Areva continues (*Nuclear Intelligence Weekly* May2,p8).

Pushing Past Hurdles To Shtokman FID

Participants in Russia's huge Barents Sea Shtokman gas development have finally agreed on the basic project design. And while several key issues remain to be resolved, the partners in Shtokman Development AG (SDAG), the operating company for the 25-year first phase, seem intent on taking a final investment decision (FID) by year's end or soon thereafter — even if some important points remain open.

That timing is in line with plans to have piped gas flows by 2016 and LNG in 2017. Russia's Gazprom holds 51% in SDAG, France's Total 25% and Norway's Statoil 24%.

A dialogue is ongoing with Moscow on tax breaks for developing the 3.9 trillion cubic meter (138 trillion cubic foot) Shtokman field. Statoil-Russia President Ian Helge Skogen told the CIS Oil and Gas Summit in Paris last week: "The Russian government has taken the initiative to see how this project could be moved forward. We are enthusiastic about this initiative-taking."

Shtokman participants realize that it will be impossible to formalize all the legislative and regulatory changes required to put tax breaks in place dur-

ing parliamentary elections due in Russia this December and the presidential election in March 2012.

However, foreign partners say that some kind of letter of intent from the government guaranteeing that allowances will be introduced would be adequate to allow an FID. Insiders say they are sure Moscow will grant the tax breaks, given the project's importance for Russia.

The Shtokman partners maintain that the field costs too much to develop under the current tax regime. They want the same kind of tax breaks as the rival Yamal LNG project, led by Russia's top gas independent, Novatek (WGI May18,p3).

The Yamal development will pay no mineral extraction tax on feedgas and enjoy preferential property and profit tax rates. Russia already charges zero duty on LNG exports, and the Shtokman partners want pipeline exports exempted, too.

Total and Statoil refuse to comment officially on gas sales or say even whether it is necessary to have a fixed percentage of future gas volumes sold before shareholders commit to spend billions of dollars on the project. But players tell WGI that the Shtokman partners have already opened sales talks, with Gazprom in charge — as expected — but the foreign partners assisting.

Total earlier said it was confident that sufficient demand would exist for the output, given already growing Asian needs and a rethink of nuclear plans by some governments in the wake of Japan's nuclear disaster (*Nefte Compass* Apr.28,p3). One source says the FID could be taken based only on such estimations of future gas demand.

"Financing is now a key stumbling block," another source tells WGI, adding that talks over the project's costs have intensified recently, but that any decision is still a long way off. Options said to be on the table include either a 60-40 or 70-30 split between shareholder equity and borrowing. Analysts say that either of the equity-heavy options would help significantly reduce project costs.

One issue that isn't yet fully resolved but may have to be for FID is the mechanism through which foreign participants would be able to book Shtokman reserves.

Michael Borrel, Total E&P senior vice president for Continental Europe and Central Asia, told the Paris conference that the final legal mechanism for booking has to be in place at the time of FID.

The SDAG shareholders did recently clear one key technical stumbling block, opting for a dual-phase flow of gas and condensate to shore from the Shtokman floating production unit via two 550 kilometer parallel pipes — the approach favored by the foreign partners. Gazprom was pushing for a single-phase option, whereby gas would have been separated from condensate on the platform (WGI Feb.23,p1).

Asian Arbitration

Might the arbitration fever that is sweeping Europe spread to Asia? Not immediately, but the groundwork is starting to be laid.

Asian buyers are increasingly seeking sophisticated price-reopener clauses that allow either party to seek negotiations when oil-linked term prices deviate too much from spot LNG prices, as happened in the last couple of years, a well-known industry lawyer tells WGI (WGI Feb.16,p1).

"They are coming with new criteria — the ability to go for arbitration if negotiations cannot reach a conclusion," he explained. Most Asian term contracts provide for price reviews every five years, but nothing is done if the seller and buyer cannot reach a deal.

Sellers are reluctant to agree to such clauses but may instead accept more frequent price reviews, says Tony Regan from Tri-Zen Consulting, "say once a year." Not even all buyers like price reopeners. "They are not always helpful, as they are time-consuming and imply a lot of uncertainty ... They could work against buyers when the markets reverse," notes a source with a large Asian utility.

The notion that arbitration can work for the seller, too, is one Spain's Gas Natural (GN) has learned the hard way: It is now appealing an arbitration ruling that left it owing state Sonatrach \$2 billion for underpayment for Algerian gas in 2007-

09, while simultaneously trying to negotiate a settlement. GN recently denied Spanish press reports that it might give Sonatrach 10% of its equity in partial settlement of the dispute (WGI May11,p5).

Another Northeast Asian buyer gives similarly short shrift to arbitration: "It's unlikely for price-openers and arbitration clauses to become a regular feature in Asian term contracts. In 2006-09, we had more than five to six price review negotiations ongoing at the same time, but most have been settled. Only a few remain. Those price reviews which have been settled include those with Qatar and Brunei."

Expressing another sentiment that has been strained past the breaking point in Europe, this source adds: "As LNG contracts are usually long-term, it is essential to maintain friendships with suppliers. It's more efficient to avoid arbitration. We should respect prices which have been concluded in price reviews."

Italy's Edison and Germany's RWE have already said they are in arbitration, having failed to reach agreement in multiple price renegotiations, and E.ON Ruhrgas is not ruling out taking one-time close ally Gazprom to arbitration (WGI May25,p2).

Jamaica LNG Jumble

Just weeks ago, Jamaica's government appeared poised to issue by June a request for proposals to supply a planned 1.2 million ton per year (158 million cubic foot per day) floating regas terminal, spurred on by growing regional supply options and the huge gap between oil and US-related gas prices (WGI May24,p4). However, recent events have cast a cloud over the project's future.

Following a year-long investigation by the Office of the Contractor General of Jamaica (OCG) into alleged corruption involving the selection of an Exmar-led consortium to build the LNG project, the OCG has "strongly recommended" that the current tender process be abandoned and a new one be held under the "supervision and scrutiny" of the commission.

Prime Minister Bruce Golding told

local media last week that the LNG project will be put out to tender regardless, as "diversifying Jamaica's energy sources is critical." But the timing and details remain to be seen.

The OCG last June seized documents and emails relating to the tender from the Ministry of Energy and Mining (MEM) and state Petroleum Corp. of Jamaica (PCJ) (WGI Jun.30,p3).

The lengthy OCG report that was just issued notes the "unearthing of overwhelming and incontrovertible evidence which is indicative of a lack of transparency, the absence of fairness, and a glaring demonstration of impropriety and irregularity in the circumstances which surrounded the bidding process."

The commission concluded that the integrity of the entire project had been compromised by Jamaica LNG project

coordinator Stephen Wedderburn's prior involvement with Exmar Marine, as well as his relationships with individuals instrumental in evaluating the bidding and his "inappropriate" presence at bidding meetings.

The OCG alleges that Exmar received information not available to other bidders, giving it a significant advantage, and that Exmar had had a working relationship with the Jamaican government since 2006 and had presented an LNG proposal to the government prior to the bidding process.

Exmar responded with a statement maintaining that its selection for the Jamaica LNG project was made with "total transparency and in full compliance with Jamaican bidding regulations" and that, given the time already spent on the project, "it would be against the interest of Jamaica to negate the award."

Exxon's Tillerson on Pipeline Taxes

The right state fiscal regime is essential to the success of a pipeline from Alaska's North Slope to a connection with the North American pipeline grid, Exxon Mobil Chief Executive Rex Tillerson told journalists in Dallas after last week's shareholders meeting (p10).

He didn't disclose the exact terms Exxon and partner TransCanada PipeLines are seeking, but WGI understands the companies would prefer a system that is "back-end loaded," starting with a low rate that would climb over the life of the pipeline, say 40 years.

Such an arrangement would help the two sponsoring companies recover their investment in the early years, while the state of Alaska would have a known revenue stream for the operating life of the project. A gradually rising take from the pipeline tax regime also would help the state offset any decline in royalties from falling gas production.

"Obviously the fiscal arrangement has a lot to do on the overall economics of the project and the competitiveness of that gas," Tillerson said. "We believe the gas can be competitive, but it's going to require all of those elements — as capital efficient a project as we can engineer,

and we've got to have fiscal supports."

He pointed out that the biggest cost in getting the Alaska North Slope gas to market will be the transportation system, as the major upstream investments were made years ago along with development of the region's billions of barrels of oil. The price tag of a pipeline from Prudhoe Bay to the British Columbia-Alberta border in Canada has been put in excess of \$40 billion.

Tillerson, as ever, evaded any specific discussion of future gas price assumptions. "We're not in the business of predicting what prices are going to be, so we're going to have to make a decision on this — as we do with all investments — as to whether we think it has the opportunity to perform across a range of pricing environments."

"For the decades it would be supplied to the market, there will be some good years and some bad years, but that's the case for everything we do." With 35 trillion cubic feet of proved reserves and 100 Tcf of probable reserves on the North Slope, "the resource is huge," he said. "The supply would be available for years and years. We don't get too wrapped up in the today and now."

ICE UK GAS FUTURES

Contract Month	May 27* p/therm	Week's High/Low	May 27* \$/MMBtu
Jul. '11	58.93	59.00/57.40	9.71
Aug.	59.85	59.95/58.85	9.86
Sep.	59.50	...	9.80
Oct.	64.90	...	10.69
Nov.	70.06	...	11.54
Dec.	72.78	...	11.99
Jan. '12	73.94	...	12.18
Feb.	73.25	73.25/71.95	12.07
Mar.	71.73	...	11.82
Apr.	66.67	...	10.98
Q3'11	59.43	59.50/58.10	9.79
Q4'11	69.25	...	11.41
Q1'12	72.97	...	12.02
Q2'12	65.38	...	10.77

Prices are based on delivery to National Balancing Point, within National Grid Gas' high-pressure transmission system. Quotes for specific dates are settlement prices. Week's High/Low reflects intra-day trading. *UK markets were closed Monday, May 30.

NYMEX US GAS FUTURES

Contract Month	May 27† \$/MMBtu	Week's High/Low	May 23† \$/MMBtu
Jul. '11	4.518	4.56/4.23	4.393
Aug.	4.557	4.60/4.29	4.438
Sep.	4.577	4.62/4.31	4.465
Oct.	4.614	4.65/4.35	4.510
Nov.	4.759	4.79/4.55	4.667
Dec.	4.971	5.00/4.75	4.885
Jan. '12	5.083	5.11/4.87	5.002
Feb.	5.072	5.09/4.88	4.993
Mar.	5.006	5.02/4.83	4.935
Apr.	4.857	4.88/4.71	4.801
May	4.872	4.89/4.73	4.821
Jun.	4.907	4.92/4.77	4.861
12-m. strip*	4.816	4.82/4.69	4.731

Delivered to Henry Hub, Louisiana. Quotes for specific dates are settlement prices. Week's High/Low reflects intra-day trading. *Average of 12 contracts. †US markets were closed Monday, May 30.

MARKET INSIGHT — Quick Storage Fills

Storage is at the heart of US market sentiment right now — both bullish and bearish. For the moment, the bulls are holding the cards, as near-record heat this week in the key US Northeast and Mid-Atlantic markets confirms early expectations for hot weather into the first two weeks of June, increasing the likelihood that storage will fall farther behind last year. But the bears did get at least a brief lift last week, when the US Energy Information Administration reported a 105 billion cubic foot (2.975 billion cubic meter) build for the week ended May 20, bringing working gas inventories to 2.024 trillion cubic feet. The build was well over the 95 Bcf five-year average for the week, reducing the deficit to 1.3%, as well as last year's revised 100 Bcf build, reducing that deficit to 10.2%. Analysts were expecting a build of around 93 Bcf on average.

Market bears still expect US storage to start ramping up rapidly, but a hot early summer may be taking its toll. This week's report should be instructive. While a number of forecasters see triple-digit builds for the next few weeks, Jeffries analyst Subash Chandra expects a smaller, 90 Bcf injection for the week ending May 27, which would be in line with last year's 88 Bcf build, but under the 99 Bcf five-year-average. The dichotomy may have to do with the impact of hot weather on gas-fired power generation. In particular, some analysts may be underestimating the effect of rising temperatures in Texas, home to about one-quarter of all US gas-fired capacity.

The storage picture across the Atlantic, meanwhile, looks increasing bearish. Inventories in all Western European regions except France are now over 50% full, with the region as a whole just over 64% full, versus just 52% a year-ago. In Germany, the storage fill-rate is over 72%. Western Europe stocks had reached 46 Bcm (1.63 Tcf) on Sunday, of which 31.5% was in Germany and 22% in Italy.

Italian storage is dominated by Eni-run Snam Rete Gas, which owns 14 Bcm of capacity, most made available to a range of commercial gas shippers, with some held as strategic government storage. Now a modest new player is emerging: Enel Stoccaggi, owned 51% by power incumbent Enel and 49% by investment fund F2i, last week received conditional approval from the Environment Ministry in Rome to convert the formerly Eni-owned Romanengo gas field, near Cremona, into a 270 million cubic meter working gas storage facility. It is aiming for operation in 2013 (WGI Jul.16'08,p5).

In Europe outside the former Soviet Union, Societe Generale analysts last week wrote that only GDF Suez's Storengy and E.On are in the same league as Italy's Snam. Second-placed Storengy has 12 Bcm in operation and E.On fractionally less. Gazprom has overtaken RWE to become the region's fourth-largest storage operator. While German RWE has about 5 Bcm in operation, Gazprom now has slightly more — thanks to its part-owned and recently expanded Austrian storage unit (WGI May25,p6). UK-based Centrica is sixth at just over 3.5 Bcm.

VOLUMES OF GAS IN ATLANTIC BASIN STORAGE

	North America					Europe								Regional Totals *		
(In Bcf)	US Prod. Regions	US East	US West	US Total	Canada	Germany	Dutch TTF**	Austria Baumgarten††	Belgium Zeebrugge	UK NBP	Spain***	France***	Italy PSV	Western Europe	North America	Atlantic Basin
Most recent †	902	860	262	2,024	271	513	47	332	13	108	52	203	359	1,626	2,295	3,921
Prior Week	864	804	251	1,919	251	507	46	322	12	102	51	190	350	1,580	2,170	3,751
Year-ago	845	1,047	377	2,269	396	394	30	290	6	72	NA	NA	306	1,327	2,665	3,993
3-year Avg.	882	953	333	2,169	345	228	25	178	2	39	NA	NA	184	804	2,513	3,317
Most Recent % Full				48.1	38.7	72.3	64.2	60.0	54.5	64.1	62.3	46.2	68.0	64.3	47.0	54.2
(In Bcm)																
Most recent †	25.5	24.4	7.4	57.3	7.7	14.5	1.3	9.4	0.4	3.0	1.5	5.8	10.2	46.0	65.0	111.0
Prior Week	24.5	22.8	7.1	54.3	7.1	14.4	1.3	9.1	0.3	2.9	1.4	5.4	9.9	44.7	61.5	106.2
Year-ago	23.9	29.6	10.7	64.3	11.2	11.1	0.9	8.2	0.2	2.1	NA	NA	8.7	37.6	75.5	113.1
3-year Avg.	61.4	27.0	9.4	61.4	9.8	6.4	0.7	5.0	NA	1.1	NA	NA	5.2	22.8	71.2	93.9

Sources: US -- Energy Information Administration. Canada -- Enerdata. European Hubs - Gas Storage Europe (GSE). * Not comprehensive. Includes only market or regions listed individually in this table. † North American data valid as of May 20, European data valid as of May 29. ** Also covers Denmark. ††Also covers Hungary, Czech Republic and Slovakia. *** GSE and therefore WGI have moved data for storage volumes in the PEG Sud and TIGF regions of Southern France out of "Spain" and into "France." The Spain column now contains data only from Enagas, and the France column now contains data from all three French sub-regions. Historical numbers for these two regions are not comparable to GSE numbers going forward. Therefore WGI will not for the time being include historic comparisons for them.

Southwest Europe LNG, NBP Prices Soar as Asia Edges Higher

European spot LNG prices shot up on Germany's decision to keep much of its nuclear capacity permanently off line, while Asian prices continue to edge up on the back of brisk buying to meet summer power demand. The Southwest Europe price jumped 80¢ from last week to \$10.30 per million Btu, but Northeast Asia retained a hefty \$3.30/MMBtu premium, as the price in that region rose 20¢ to \$13.60, according to WGI price assessments from Monday for Asia and Tuesday for Europe, for spot cargoes for delivery four to eight weeks out.

Germany's announcement Monday that it will be keeping its eight oldest nuclear plants off line and closing the rest of its reactors by 2022 pulled the UK National Balancing Point (NBP) day-ahead price up 32¢ to \$9.65/MMBtu Tuesday, as assessed by WGI, while July futures shot up 48¢ to \$9.71 on ICE. Netbacks for Mideast suppliers are roughly \$3.10/MMBtu higher on Asian than on Southwest European sales, while for Africa exporters, Asia's netback advantage is about \$1.50 (see table below).

Most Japanese buyers have wrapped up July talks and are in discussions for August and September arrivals, traders say, although Kansai Electric and Kyushu Electric are reportedly still wrapping up July deliveries. Taiwan's CPC has also concluded July buying. It is understood to have taken a spot cargo from Peru for June arrival. Although some sellers are still marketing prompt cargoes, prices are expected to firm further in the absence of clear signals as to when nuclear reactors in Japan can restart and forecasts for a warmer-than-average summer. A source from Tokyo Electric (Tepco) says it never buys based on weather forecasts, so that utility could need a top-up if such heat materializes.

The first full-month data since Mar. 11 show Japanese imports

of Qatari LNG jumped 57% to 997,046 tons in April, while Russian supplies soared an equivalent 56.4% to 724,469 tons. Total April imports increased 8.8% to 6.01 million tons. China National Offshore Oil Corp. is heard to have been offered extra term volumes by Qatar but it is unclear whether the buyer took up the offer, since spot cargoes are still a better buy than tightly oil-linked term supply. Last week, PetroChina received a first commissioning cargo from Qatar at its new Rudong import terminal, and has reportedly secured a second Qatari commissioning cargo for late-June arrival. The 3.5 million ton/yr terminal — PetroChina's first — is slated to receive Qatari cargoes under a 3 million ton/yr Qatargas 4 contract. PetroChina is also heard seeking a commissioning cargo for its second terminal, at Dalian.

India's Gail is looking to buy July cargoes, but by August, demand could ease with the expected arrival of the monsoon. Market players barely reacted to news that BP shut down Train 2 at the Tangguh plant in Indonesia last weekend for one and a half months since it is scheduled maintenance.

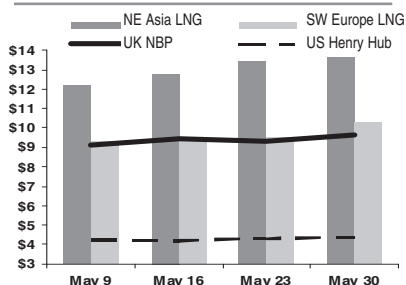
The recent jump in the Mediterranean price has as much to do with the region's market conditions as with Germany's decision to shut down nuclear power, sources tell WGI.

"Southwest Europe is just continuing recent strong trends," a trader said. Greece is notably active, while Spain is still not seeing spot deals. "There is nothing going on [in Spain] ... We have not made any deals at all," one trader moaned.

Even with continuing maintenance outages in Norwegian gas fields, traders say that the UK remains well supplied amid strong LNG imports. Three Qatari cargoes were added to South Hook's schedule over the week: Jun. 2 on the *Al-Mayeda*, Jun. 3 on the *Zarga*, and Jun. 7 aboard the *Maersk Magellan*. A Nigerian cargo aboard the *Methane Kar Elin* is due Jun. 2 at Dragon LNG.

INDICATIVE LNG, SPOT GAS PRICES

(\$/MMBtu)	Current	Previous
Northeast Asia LNG	\$13.60	\$13.40
Southwest Europe LNG	\$10.30	\$9.50
	Spot	Futures
Britain's NBP	\$9.65	\$9.71
US Henry Hub	\$4.36	\$4.52



Source: WGI assessments of spot prices for LNG in NE Asia and SW Europe and for day-ahead gas in the UK. NGW spot assessment for US. The Asian price is for Monday, May 30. The Southwest Europe LNG and UK spot prices are for Tuesday, May 31. The US prices and the UK futures price are for Friday, May 27.

SPOT LNG EXPORTER NETBACKS AT KEY MARKETS WORLDWIDE

(Netbacks in \$/MMBtu) Exporters	Northeast Asia*	Southwest Europe**	UK***	Belgium Zeebrugge†	US Gulf Coast††	US Southeast†††	US Mid-Atlantic‡	US Northeast‡‡	Canada Canaport§	Mexico Costa Azul§§	Mexico Altamira§§§
Qatar	\$11.80	\$8.70	\$7.06	\$7.15	\$1.54	\$1.82	\$2.31	\$2.46	\$1.72	\$1.59	\$1.72
Oman	\$11.95	\$8.84	\$7.29	\$7.27	\$1.68	\$1.95	\$2.44	\$2.59	\$1.95	\$1.73	\$1.98
Abu Dhabi	\$11.83	\$8.74	\$7.13	\$7.19	\$1.59	\$1.89	\$2.36	\$2.57	\$1.76	\$1.64	\$1.81
Indonesia	\$12.72	\$8.02	\$6.51	\$6.42	\$1.34	\$1.37	\$1.82	\$1.93	\$1.16	\$2.31	\$1.52
Malaysia	\$12.67	\$8.07	\$6.57	\$6.66	\$1.32	\$1.35	\$1.80	\$1.91	\$1.14	\$2.25	\$1.70
Australia	\$12.50	\$7.98	\$6.51	\$6.54	\$1.46	\$1.52	\$1.95	\$2.06	\$1.28	\$2.19	\$1.68
Russia	\$13.18	\$7.60	\$6.21	\$6.29	\$0.91	\$0.94	\$1.43	\$1.50	\$0.74	\$2.69	\$1.09
Trinidad	\$10.05	\$9.37	\$7.76	\$7.82	\$3.24	\$3.26	\$3.69	\$3.73	\$2.94	\$1.64	\$3.43
Algeria	\$10.69	\$10.03	\$8.14	\$8.20	\$2.77	\$2.89	\$3.39	\$3.53	\$2.75	\$1.38	\$2.91
Egypt	\$11.10	\$9.71	\$7.88	\$7.97	\$2.54	\$2.67	\$3.17	\$3.31	\$2.52	\$1.09	\$2.73
Nigeria	\$10.69	\$9.31	\$7.65	\$7.71	\$2.54	\$2.59	\$3.09	\$3.20	\$2.45	\$1.60	\$2.76
Eq. Guinea	\$10.78	\$9.38	\$7.70	\$7.78	\$2.61	\$2.67	\$3.17	\$3.27	\$2.49	\$1.65	\$2.80

All netbacks and LNG price assessments are for standard cargoes of 125,000-150,000 cubic meters. All LNG and spot gas prices used in netback calculations are for the Monday prior to publication except when that Monday is a public holiday. In that case, the price for the market with the holiday is for the preceding Friday. * Applies to all Japanese, South Korean terminals. Based on WGI LNG spot price assessment. Assessed price appears in small table above. ** Applies to all Spanish, Portuguese and Italian terminals able to handle vessels carrying 135,000 cubic meters of LNG. Based on WGI LNG spot price assessment. Assess price appears in small table above. *** Applies to all UK terminals. Based on WGI NBP spot price assessment for day-ahead gas. † Based on WGI Zeebrugge spot price assessment for day-ahead gas. †† Applies to Cameroon, Freeport, Lake Charles and Sabine Pass terminals. Based on Louisiana Gulf Coast Offshore composite spot prices from Natural Gas Week. ††† Applies to send-out from Elba Island terminal that does not go to Florida. Based on Southeast composite spot price from NGW. ‡ Applies to Cove Point terminal. Based on Mid-Atlantic composite price from NGW. ‡‡ Applies to Everett, Neptune and Northeast Gateway terminals. Based on Northeast composite spot price from NGW. § Based on Northeast composite spot price from NGW, adjusted for transport charges to Dracut. §§ Based on California South composite spot price from NGW. §§§ Priced at HH plus 20¢/MMBtu

GE, IEA Both Address Intermittent Power Need — In Their Ways

Former UK Prime Minister Harold Wilson once famously said that “a week is a long time in politics.” That was decades ago. Nowadays, in a more immediate world, savvy politicians might well substitute “hour” or even “minute” for Wilson’s “week.” The same can be said for electricity. In the 1970s, intermittent renewables such as wind and solar were virtually nonexistent. Today they are a ubiquitous part of the global energy mix. Handling intermittency has become a game of minutes rather than hours.

Underscoring the importance of minutes in electricity system balancing is word that US-based General Electric has developed a gas-fired turbine capable of bringing 50 megawatts of power online per minute, twice the ramp-up rate of any gas-fired unit currently on the market, GE claims. By comparison, coal-fired stations can take hours and nuclear plants days to bring on line or shut down. GE also claims an impressive 61% efficiency rate for its 510 MW FlexEfficiency unit, which is capable of running in both combined- and single-cycle modes, with single-cycle obviously favoring quick response over efficiency. “Operational flexibility at these levels will enable utilities to deliver power quickly when it is needed and to ramp down when it is not, balancing the grid cost-effectively and helping to deploy additional renewable power resources like wind and solar,” GE says.

The International Energy Agency (IEA) addresses the challenge of managing increasing quantities of intermittent renewables in *Harnessing Variable Renewables: A Guide to the Balancing Challenge*. Released last week, the study looks at Japan, the British Isles, the Iberian Peninsula, Mexico, the Nordic countries, Denmark, the US Western Interconnection and the New Brunswick system in Eastern Canada. Using four reference periods — 15 minutes, one hour, six hours and 36 hours — to study these eight very different electricity markets,

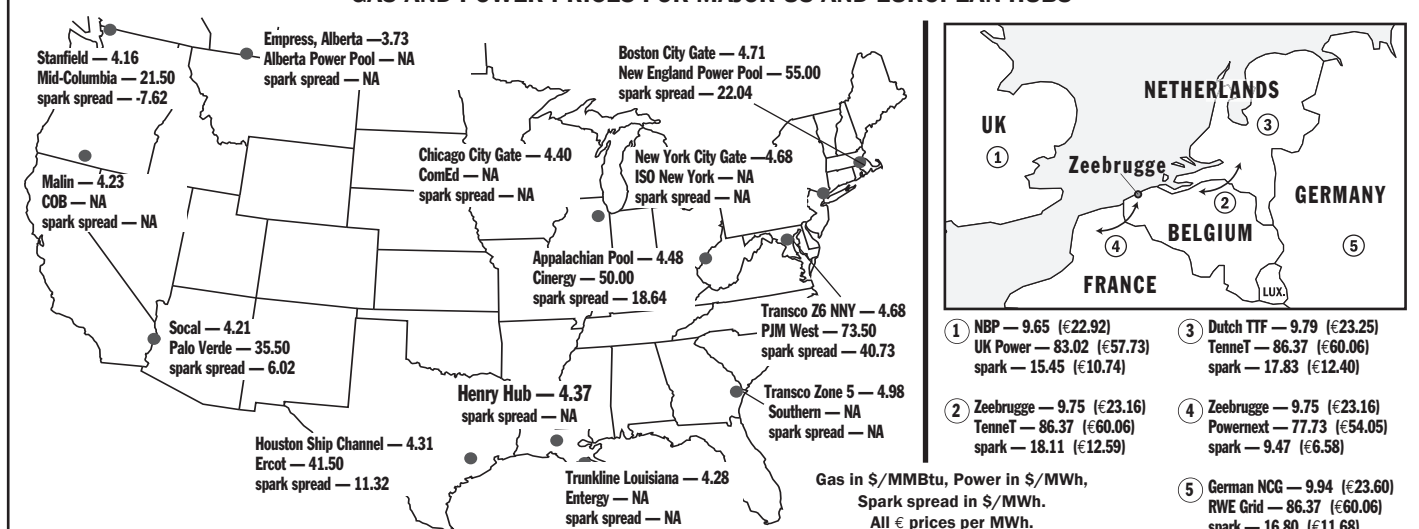
the IEA report concludes that “power systems have greater capacity to handle variable, renewable electricity — wind, solar, tidal and wave power — than commonly believed.” This follows a report released earlier this year in which the IEA more broadly champions the role of renewables in curbing greenhouse gas emissions, while raising concern over the global addiction to coal and other fossil fuels for power generation (WGI May4,p8).

Denmark came out tops in terms of overall system flexibility, with a rating of 63%, boosted by plenty of interconnectivity to surrounding markets. The forward-thinking Danes outlined scenarios last year to rid the country of fossil fuels within a few decades (WGI Oct.20,p7). Japan came out on the bottom with 19% flexibility, due to its heavy reliance on nuclear and fossil fuel generation. This could change quickly, however, with Japan set to embark on a major campaign to expand solar and possibly other renewable capacity (WGI May18,p8).

The British Isles have an overall flexibility of 31%, according to the study. Highlighting just combined-cycle gas turbine (CCGT) performance and excluding other generation assets, the study found that 40% of CCGTs in the UK are available to come online within 15 minutes on average, 50% within an hour and 100% within six hours. For the Iberian Peninsula, with an overall flexibility of 27%, the report notes that roughly 18% of CCGTs are reactive within 15 minutes, rising to 55% within an hour and all within six hours (WGI Apr.27,p9).

For the Western Interconnection of the US, with a 45% overall flexibility rating, the report makes an assumption that, by 2017, roughly 26% of dispatchable plant will be CCGTs, 25% coal, 16% open cycle gas turbines and 4% nuclear. It forecasts that 50% of CCGTs will be responsive within 15 minutes, and the rest within one hour. Mexico was given a flexibility rating of 29%, the Nordic region 48% and New Brunswick 37%.

GAS AND POWER PRICES FOR MAJOR US AND EUROPEAN HUBS





Gas Gets Second Chance for Position in Europe's Energy Future

Europe's gas industry felt slighted last year when, in long-term EU and German strategic planning, natural gas was shown not as the least-polluting fossil fuel, nor as a transition fuel to a cleaner future, but as part of the smokestack past. Nuclear, renewables and other "decarbonizing" fuels and technologies gained top billing, certainly in the German energy concept published in September 2010 (WGI Sep.15,p8).

This year two things have given gas a fresh chance — although more may be required. First, the gas industry has found its voice: Lobby groups such as the International Gas Union (IGU), regional counterpart Eurogas, and even the Russian Gas Society (RGS) have gone on the offensive — sometimes stridently and to the dismay of the renewables industry and green activists.

IGU President Rahim Hashim of Malaysia has been rallying the troops: On May 25, he spoke at the annual gathering of Spanish association Sedigas, which has seen gas sales hit by subsidies for coal-fired power. Two weeks earlier he presided at a 17-nation IGU Summit in Germany of 33 top gas executives that agreed on a "Munich Declaration," which among other things takes on the inherently difficult task of challenging "the perception that gas is a fossil fuel along with coal and oil."

Second and fundamentally, confidence in nuclear power has been shaken around the world by the severe damage to 1970s-built Fukushima-Daiichi nuclear complex resulting from Japan's Mar. 11 earthquake and tsunami (WGI May18,p8). Germany's center-right government, until March among the most pro-nuclear in Europe, has now permanently shut down eight older reactors and plans to close all its nuclear plants by 2022, a return to the timetable enacted by the now-opposition Social Democrats and Greens in 2000 (WGI Apr.13,p8).

Standardized criteria for safety testing the EU's 143 reactors were announced May 25 by the European Commission. Contrary to German and Austrian wishes, the test does not cover plants' ability to withstand terrorist attacks. Reports will be due Oct. 31 for review by national regulators, and the 14 EU states with reactors are to file national reports by Dec. 31. Non-EU Switzerland also said last week it would not replace its five aging nuclear plants as they retire between 2019 and 2034 — a policy that will raise Swiss reliance on gas-fired power.

Beyond public relations and exploiting nuclear's misfortunes, a third strategic plank may be required to give gas a long-term future. In *Does Natural Gas Need a Decarbonisation Strategy?*, a study published by the Oxford Institute for Energy Studies, Floris van Foreest argues, "Relying on a continuation of current developments for the next 10 years risks a sunset scenario for gas." To achieve an 80% cut in greenhouse gases by

2050, drastic changes in energy use will be required, and he presents two decarbonization options for gas that could mitigate a long-term slide in its use: carbon capture and storage (CCS) with gas-firing, and making the gas grid more "green" by comingling biogas into the stream. The UK, Netherlands and Germany have made progress in injecting biogas into gas grids.

Two weeks ago in Berlin at the annual gathering of Eurogas and RGS, E.ON Ruhrgas chief Klaus Schafer criticized Germany's September 2010 Energy Concept 2050, adding that a follow-up "German Energy Concept 2.0 is not yet prepared, but I'm convinced that gas will play a bigger role." Eni gas and

power chief Domenico Dispenza told the same event: "The European gas industry has a role to play in the future energy mix and not at the expense of renewables. Gas is part of the solution." Eurogas forecasts are for EU gas consumption to reach 595 billion-637 billion cubic meters in 2030, up 14%-23% from 2007 levels, or 1% per year compound growth, he said, with the largest share of the increase coming from power generation. "We need EU policymakers to recognize ... gas is an ideal partner... It can balance the intermittency of renewables."

Philip Lowe, the top official reporting to EU Energy Commissioner Gunther

Oettinger, insisted in Berlin that EU officials see gas "at the center of the energy debate in the medium and long-term," whether as a destination or transition fuel: "Gas is likely to offer more certainty than any other fuel being discussed." Russia provides 40% of EU gas imports, and "we expect that to continue" as, whatever the benefits of LNG, "pipeline gas is a core basis for a successful European energy supply." Consultation with Russia through a "Gas Advisory Forum" about the EU's 2050 Road Map would "we hope ... create consensus," Lowe added.

IGU Secretary-General Torstein Indrebo, however, preferred a clarion call over consensus-building: "All coal should be replaced by gas-fired power plants." The official, who hails from hydro-rich Norway, which only recently started using gas in power plants, also told his Berlin audience that not only is gas cheaper than oil, it "is cheaper than coal" — a highly debatable point (WGI May25,p9). Indrebo was on safer ground when he said the recoverable gas resources-to-production ratio has extended to 250 years due to the addition of unconventional gas, although he again entered controversial territory by calling the resource base "more or less unlimited."

A UN report last week said that by 2050, the world could be devouring roughly 140 billion tons per year of minerals, ores, fossil fuels and biomass — three times more than now — unless economic growth rate is "decoupled" from natural resource use.

**Floris van Foreest
argues, "Relying on
a continuation of
current developments
for the next 10 years
risks a sunset
scenario for gas."**

Mark Smedley, London

Alaska Gas Pipeline: 40 Years on, Prognosis Still Uncertain

Since the late 1960s when Humble Oil, now Exxon Mobil, and Standard Oil of Ohio, now BP, discovered the largest single oil and gas field in the US at Prudhoe Bay on Alaska's North Slope, they have been trying to find an economically viable way to get the natural gas to market. Getting an oil pipeline to an export terminal at an ice-free port 800 miles away was a big enough challenge. It took the 1973-74 Arab oil embargo to galvanize political support and overcome environmental opposition. Oil finally began flowing in 1977.

Expectations were that a gas line to the US lower 48 would follow shortly, but more than 40 years have passed, with two high-profile proposals — the Alaska Northwest project and, recently, BP and ConocoPhillips' Denali venture — going to their graves. Alternative plans to ship the North Slope gas via in-state lines to Valdez, near the existing oil port, and convert it into LNG have not gained needed traction either.

So what are prospects for the remaining proposal on the table, TransCanada PipeLines and Exxon Mobil's pipeline project? The sponsors offered prospective shippers two configurations during last year's open season: a line connecting to Trans-Canada's Canadian transport infrastructure into the US, or a line to Valdez, where an LNG plant could be constructed by a third party. Results of the open season have not been disclosed. TransCanada Vice President Tony Palmer tells WGI that the project is on schedule to file for clearance with the Federal Energy Regulatory Commission in October 2012. Most, but not all, pipeline-customer issues have been resolved, he said, without indicating whether customers favor LNG or the line into the main North American grid.

Palmer did take issue with one reason Denali officials gave for pulling the plug on their project: the abundance of shale gas and resulting low gas prices. "Firstly, gas prices today are not what the project is focused on. It's really ... gas prices beyond 2021 and for the next 20-50 years that matter," Palmer said. "It is the view of our customers that matter, and what a pipeline company can try to do is get a commercial deal that will work for the parties."

Partner Exxon, the largest gas reserves holder in Alaska, isn't talking much (p5). However, Exxon is also one of — if not the — largest holder of unconventional gas resources in North America. If shale were an impediment, why would Exxon be involved in an Arctic gas pipeline of any sort, either in Alaska or in Canada's Northwest Territories, where its Imperial Oil affiliate leads the Mackenzie Gas Project (WGI Jan.12,p4)?

Bill Gwozd, vice president of gas services for Calgary-based consultancy Ziff Energy, shares what is apparently

Exxon's view, that by 2020 and beyond, shale gas may not be an issue, given the rapid decline in conventional supplies in Western Canada and the Gulf of Mexico. Gwozd says that North America will eventually need not only Alaskan gas, but all the shale Canada and the US lower 48 can supply, as well as LNG imports to balance the market — not LNG exports.

North Slope operational considerations have to be factored into the equation, too. Prudhoe Bay long since became a gas field with associated liquids rather than an oil field with associated gas, as it was initially. The gas handling plant at Prudhoe Bay processes about 9 billion cubic feet per day (93 billion cubic meters per year) of raw gas. After NGLs, carbon dioxide and gas for local use are extracted, about 8 Bcf/d is re-injected into the field. The CO₂ also goes for enhanced oil recovery.

Exxon has begun developing the adjacent Point Thomson gas-condensate field even though some lease issues with the state have yet to be resolved (WGI Dec.8,p8). For now, the gas will be cycled and the condensate recovered and mixed with North Slope crude to help keep TransAlaska Pipeline System supply above minimum operating levels. However, Point Thomson gas will eventually have to be produced.

Alaskan North Slope wells are already drilled, so that cost is sunk. The main cost of getting the gas to market is a transportation system — which won't be cheap. The TransCanada-Exxon project offered producers a choice between a 40 inch, 3 Bcf/d LNG option or a 52 inch, 4.5 Bcf/d link into TransCanada's existing system at the British Columbia-Alberta border. Depending on the configuration, cost estimates vary from \$20 billion to \$41 billion.

Three LNG projects have been proposed for British Columbia, two near Kitimat and one for Prince Rupert. These would be too distant for Alaskan gas to be economical as feedgas, especially with trillions of cubic feet of unconventional gas available nearby, so they would be competing with Alaskan LNG for markets in Japan, South Korea and China. Royal Dutch Shell, operator of 2 Bcf/d BC LNG at Prince Rupert, has a partner in each nation — Mitsubishi, Korea Gas (Kogas) and PetroChina — plus other long-standing Asian customers. Apache, EOG and Encana are partners in the 700 million cubic foot per day Kitimat LNG, expandable to 1.4 Bcf/d. Douglas Channel LNG is a micro-project with a capacity of 125 MMcf/d (WGI Mar.23,p2).

By the time a final decision is taken on an Alaska pipeline, the Canadian LNG projects could be under construction and a clearer picture of intermediate and long-term Asian demand available. And Exxon's perspective is nothing if not long term.

*Barbara Shook in Houston,
with Lauren O'Neil in Washington*

If shale were an impediment, why would Exxon be involved in an Arctic gas pipeline of any sort?