Having secured the Upper Zakum heavy oil deal last year in Abu Dhabi, Exxon Mobil is now on the verge of something equally weighty in Kuwait. The US supermajor has signed a heads of agreement with Kuwait Oil Co. (KOC) that would involve joint development of an estimated 1 billion barrels of heavy oil reserves in the Lower Fars structure in northern Kuwait in addition to investments in the downstream and midstream that would involve the processing and marketing of some 550,000-700,000 barrels per day of heavy oil. The two sides are now heading toward detailed negotiations for the integrated deal, in which the upstream segment is modeled on an enhanced technical service agreement (TSA), where the foreign partner will not be able to formally invest or book reserves (PIW Mar.19,p3). In the first stage, Exxon will conduct a pilot scheme to confirm the potential of the Lower Fars formation in the northern Ratqa field close to the Iraqi border. Under KOC’s existing plans, the pilot project would produce some 5,000 b/d of heavy oil, with targeted output of 50,000 b/d by 2011, 250,000 b/d by 2015 and possibly up to 700,000 b/d by 2020. Kuwait turned to enhanced TSAs last year to increase the role of foreign majors in helping it reach its targeted output capacity of 4 million b/d outlined in its 2020 strategic plan, having failed to get its Project Kuwait scheme off the ground due to parliamentary opposition (PIW Aug.21’06,p3). Similar enhanced TSAs are being negotiated with BP and Chevron for field development in west and southeast Kuwait.

Even though Exxon won’t be able to book the Kuwaiti volumes, its increasing portfolio of heavy oil underlines that most of the world’s higher quality reserves are already in production, leaving heavy oil and other nonconventional resources as the only option in many areas.

Analysts See Oil Price Strength Persisting

Crude price forecasts are heading north, with pundits struggling to keep pace with the apparently inexorable rise in the futures market. Speculative cash has been fingered as the main culprit behind recent record crude prices, but a PIW poll of analysts found a near consensus that tight supply-demand fundamentals are the main drivers, that they will remain tight in the near-term — and that crude prices will stay high heading into 2008. Analysts, researchers and traders polled by PIW forecast prices for West Texas Intermediate (WTI) to average $71.27 per barrel in the fourth quarter of 2007, up about 16% from projections made earlier this year (PIW Apr.23,p1). Prices in the first quarter of 2008 are expected to remain above $71/bbl, with the average price for 2008 as a whole forecast at $69.60/bbl.

WTI rebounded off a recent low around $68.63 per barrel in August and has stayed strong into September, well beyond the same point last year when prices dropped heading into winter. With demand growth expected to match and quite possibly outstrip supply, and non-Opec production now seen increasing more modestly than previously thought, the market will remain on edge, analysts forecast. “The key marginal demand is non-OECD,” said Paul Horsnell of Barclays Capital in London — China, India and the Middle East are showing strong demand growth, while demand growth within the OECD is lackluster.

Opec’s decision to raise real output by 500,000 barrels per day was received as a token gesture — “too little, too late” was the favored phrase among traders convinced the move did little to offset
what is considered a supply crunch. Benchmark US crude futures posted record high settlements in the days following the Opec decision, and, with help from last week’s US interest rate cut, have since surged above $80/bbl (PIW Sep.17,p1). WTI has hit a string of intraday highs in response to the US Federal Reserve cutting its key interest rate and — in what is becoming a weekly theme — a bigger-than-expected drop in US crude stocks. What the rate cut will do for a recent global credit tightening and the overall economic picture heading into 2008 is still unclear. Nonetheless, the Fed’s gift has momentarily allayed fears of an economic slowdown emerging from the US subprime debacle.

Another wildcard in the forecast is the Northern Hemisphere winter and demand for heating oil. A mild winter could stifle demand but some remain bullish — Goldman Sachs sees a “high risk” of a price spike above $90/bbl before the end of the year and an average oil price of $85/bbl in 2008 (PIW Sep.17,p3). Goldman’s Jeffrey Currie sees a “structural” bull market where producers are adding little low-cost production and spending more on exploration and production while working out “technological and political bottlenecks that will likely take years to resolve.” The odd dissenting voice remains, however, arguing that higher prices caused by speculation will eventually dent demand.

### PIW Oil Price Forecasts

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#### Back To The Future At Pertamina

Indonesia’s state Pertamina is not alone among national oil companies in aspiring to inject some dynamism into an enterprise burdened by bureaucracy, history and decades of government meddling. The key to its strategy is a rash of recent accords that is already drawing major international oil companies to the country’s ailing upstream, including Royal Dutch Shell, which made its name in Indonesia but sold up in 1965 after a 75-year presence. In a PIW interview, Chief Executive Ari Soemarno outlines how he intends to turn Pertamina into an integrated oil company with a stronger upstream presence at home and abroad (Interview,p6). After signing a broad upstream memorandum with Pertamina in November, Shell is now in talks to jointly explore frontier areas offshore southern Papua. Norway’s Statoil has also secured joint exploration rights with Pertamina at the Karama deepwater block, just six months after inking an initial agreement, and Russia’s Lukoil this month finalized a detailed agreement to study three blocks in Indonesia (p5). Soemarno says Pertamina still has plenty to offer as it has the largest portfolio of acreage in the country and preferential rights to new exploration blocks (PIW Oct.2,p1).

Among its regional peers, Pertamina took an early lead in scouting for overseas assets, but it has since changed tack. Rather than rush abroad, Pertamina is now concentrating on developing its own neglected and mature domestic assets with the aim of ramping up crude production by 70% to around 180,000 barrels per day in 2009, according to Indonesian upstream regulator BP Migas. Outside the region, Pertamina’s hodge-podge of upstream assets in Iraq, Libya and Sudan is unlikely to add anything for many years to come (PIW Jul.9,p7). To date, only a regional development program with state peers — Malaysian Petronas and Petrovietnam — has contributed overseas equity output (PIW Aug.13,p6). Pertamina’s 2006 output was 107,000 b/d of oil and 944 million cubic feet per day of gas, which is expected to reach to 118,000 b/d and between 1.3-1.5 Bcf/d in 2007, according to BP Migas. The troubled Cepu block in Java, projected to peak at 150,000 b/d by 2010, will make the biggest contribution to the 2009 target.

Problems in its core LNG business have earned Pertamina an unenviable reputation for inefficiency and led to its eclipse by Malaysia’s Petronas, which had modeled its own LNG business on Pertamina’s. Instead of capitalizing on its position as the world’s top LNG exporter in the 1990s, declining gas output has forced Pertamina to purchase LNG on the spot market to meet its long-term contract obligations to foreign buyers (PIW Jun.11,p6). Still, Soemarno is optimistic about a rebound in LNG if fresh plans by US Chevron and France’s Total to boost exploration offshore East

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By its own admission, Pertamina has a long way to go. Critics point to the strained relations with Exxon Mobil over the Cepu and Natuna projects and see the new partnerships with foreign players as a test of the company’s capacity to handle change (PIW Jul.9,p6). A senior company official admitted last week that Pertamina’s role over the last 30 years was more “landlord” than contractor and it needed a new approach. “We are not embarrassed to learn,” head of corporate planning and business development Widhyawan Prawiraatmadja said. “We want to get our hands dirty and do the job.”

Total’s Tormore find to the west of the Shetland Isles and Chevron’s successful well test of the deepwater Rosebank discovery in July have refocused attention on the prospects for commercializing oil and gas reserves in one of the final frontier areas in UK waters. The inhospitable deepwater Atlantic margin is reckoned to contain up to 17% of the UK’s remaining reserves, and the government calculates it could produce an average 400 million cubic feet per day of gas over a 15-year period starting in 2013, equivalent to some 5% of current UK gas output. This is all very promising for a mature basin such as the UK North Sea, but there is still a long way to go to realize the claimed potential. A development taskforce set up in November last year, involving the government and principal operators Total, BP, Exxon Mobil, Chevron and Dong Energy, has so far identified four hub scenarios for technical and economic evaluation and decided that the three offshore options look more economic (PIW Sep.10,p9).

There is a consensus that collaboration between the major players in the region makes most sense considering the estimated $8 billion investment in infrastructure needed to bring the oil and gas to market. But the economics of development remains shaky, with all the potential options for a gas hub deemed uneconomic under current market conditions. There is also much exploration and appraisal work still to be done to confirm estimates of the area’s reserves — currently put at 2 trillion cubic feet of discovered reserves, plus a further 2 Tcf of discovered potential and 4 Tcf of undiscovered potential. The exact geology of the discovered resources is also uncertain. Most are located in Paleocene sands, similar in type to the Forties field but not as thick, and there is still considerable uncertainty as to the exact geography of the individual reservoirs. Harsh operating conditions add to the risk surrounding potential development.

Something needs to give if development is to be viable. In the quest for options the UK taskforce suggests that development costs are either trimmed by 25%, UK gas prices increase by 15%, projected future production rises by 25% — or a significant new discovery of 500 billion cubic feet to 1 Tcf is made. Even if one or more of these materialize, development in the west of Shetlands region remains challenging. BP drilled 100 exploration wells over 20 years to prove up reserves in the Schiehallion/Foinaven fields, and then had to contend with extreme operating conditions while developing the assets. Similarly, the company’s Clair field comprises an extensively layered and fractured sandstone reservoir which complicates development, contributing to an almost 30-year gap between the first discovery on the field in 1977 and first oil in 2005 (PIW Jan.31’05,p7).

The UK government could also lower costs through tax breaks or subsidies, perhaps along the lines of the new Norwegian tax law introduced last year to encourage development work on disused fields, while exploration over the next two years will be crucial for proving up more reserves and throwing more light on the area’s geology.

It’s the large independent refiners such as Valero that hog the headlines with their billion-dollar earnings but their smaller siblings are also performing nicely, with some seeing stellar gains in their stock price this year. In the US, small independents such as Western, Alon, Holly and Frontier are benefiting from high niche market margins and acquisitions, with Texas-based Western the runaway winner so far. Western had to fight US regulators to buy its rival Giant Industries and has seen its stock soar as much as 60% since the deal closed in late May. A challenge by the US Federal Trade Commission (FTC), which argued that Western would be too big in New Mexico after the Giant purchase, ultimately failed in court, enabling Western to enlarge its capacity to about 223,000 barrels per day from 117,000 b/d previously and enhance its market position in the US Southwest.

What tends to make these small refiners so profitable is their grip on niche markets with a limited number of plants or limited pipeline links to other sources of crude or products. As margins in many other areas have come off the boil, Frontier, a 170,000 barrels per day Midwest
refiner, has enjoyed exceptional margins through the third quarter. Like other smaller players, Frontier benefits from buying local crudes — which sell at a big discount to benchmark West Texas Intermediate (WTI) — to run at its Wyoming refinery. In addition, its El Dorado, Kansas unit has this year supplied areas affected by outages, both at the 108,000 b/d Coffeyville Resources refinery in Kansas and elsewhere in the Midwest. Midwest margins have averaged more than $20/bbl so far in the third quarter, almost double the rest of the country. Earlier this year, however, the dynamics were different and stock in refiner Tesoro, a 660,000 b/d West Coast independent, rose 80% on soaring West Coast margins and its acquisition of Royal Dutch Shell’s 100,000 b/d Wilmington refinery near Los Angeles. But as West Coast margins have fallen by about 75% from their May peak Tesoro’s stock has plummeted 24%, underscoring the risks of concentrating assets in a particular region with no offset from elsewhere.

In the wake of Western’s $1.3 billion takeover of rival Giant Industries, other niche refiners have not been shy about declaring their appetite for growth through acquisitions. They have cash on hand and are confident that refining margins will remain at reinvestment levels (PIW Aug.6,p3). The downside, of course, is that they do not enjoy economies of scale. This can complicate the quest for an acquisition that fits well with their existing operations. Another problem is rising asset prices, since recent deals have been at anywhere from $11,000 per b/d of capacity to $19,000 per b/d, versus a high of roughly $6,000 per b/d before 2005. Alon paid $6,270 per b/d for Paramount Petroleum last year, while Giant cost Western $12,775 per b/d (PIW May28,Suppl.).

The biggest threat to the niche refiners is a sharp decline in margins since they depend on them for their entire livelihood and are not as well placed as integrated oils with upstream assets to ride out downstream dips. A major outage at a plant can hammer cash flow as the niche players have relatively few refineries. In contrast, the partial or even complete closure of a refinery is usually a manageable financial setback for a larger independent such as Valero or a major, as it is just part of a much larger operation.

(Continued from p.1)

Last year Exxon secured a 28% stake in the Upper Zakum field, a super-giant offshore field with approximately 50 billion bbl of original oil-in-place (PIW Apr.3’06,p7). Current production capacity is around 500,000 b/d, with less than 5% of the field’s resources produced to date, according to Exxon. The plan is to raise output capacity to some 750,000 b/d over five years. The deal came around the same time as state Saudi Aramco launched the development of its Manifa field, considered the single largest heavy oil venture in the world (PIW Apr.17’06,p1). Aramco is targeting 900,000 b/d of Manifa crude by 2011 from the field’s 10 billion bbl of reserves. According to Exxon, tight gas, heavy oil, acid/sour gas, and other nonconventional resources will account for about 40% of its production by 2010, up from roughly 25% in 2005.

The Kuwait deal would compensate for the loss of Exxon’s Cerro Negro heavy oil upgrading project in Venezuela, where the company held a 42% stake and had been producing 120,000 b/d of heavy oil until earlier this year. Exxon quit Venezuela three months ago after Caracas decided to take majority control of the $3.45 billion project. Exxon’s stake in Cerro Negro accounted for only 2% of its total reserves, and provided just 1% of group output (PIW Jul.2,p1).

As American motorists fill their tanks with growing volumes of ethanol, Brazil’s Petrobras is angling to export more biofuel to the US market. With three decades of biofuel experience behind it, the state-controlled firm has a head start on the majors, which are recent entrants to the sector. As rising oil and biofuels production has made Brazil energy self-sufficient, so Petrobras has turned its attention to making a modest ethanol surplus the basis of a global biofuel business. The company — which pioneered the process of converting sugar cane into biofuel — has numerous greenfield and expansion projects under way to lift ethanol output to nearly 600,000 barrels per day in 2012 from 300,000 b/d currently. Because nine out of 10 new vehicles sold in Brazil are flex-fuel vehicles, enabling them to run on traditional gasoline or an ethanol blend, most of the ethanol is consumed domestically, with just 60,000 b/d exported. Early next decade, following completion of two ethanol pipelines to the country’s coastal shipping centers, export volumes will double to 120,000 b/d, with the US the main target destination.

Brazil’s rise to dominance in the ethanol business resulted from government mandates designed to cut reliance on fuel imports when oil prices soared back in the 1970s. Petrobras argues that similar mandates on fuel usage goals are needed in the US if the market is to
take off. Somewhat surprisingly, however, not all Brazilians are pushing the US to slash the 54¢ per gallon tariff on ethanol imports, due to run to 2009, which protects US Midwest farmers who grow corn for corn-based ethanol. Roberto Giannetti, a long-time Brazilian trade official, suggests a phase out of tariffs over several years. Wiping out the tariff at once would disrupt both US and Brazilian markets, he argues, as large volumes of Brazilian ethanol would be drawn to the US, where prices are higher. The US currently has 112 active ethanol refineries producing around 333,000 b/d, which should rise to 750,000 b/d when a further 76 refineries, now under construction, are completed. US President George W. Bush is proposing a mandatory fuels standard that requires roughly 2.3 million b/d of renewable and alternative fuels to be blended into gasoline by 2017, five times current levels. Several US lawmakers are also moving to mandate greater biofuel use and the manufacturing of more flex-fuel vehicles (PIW Aug.20,p4).

Apart from its interest in the US market, Petrobras has recently struck partnerships with Japanese traders Mitsui and Itochu to promote ethanol production in Brazil for export and is working with Italy’s Eni and Portugal’s Galp in Europe to build biodiesel plants, using vegetable oil and other types of waste product. But there is a downside, with the growing amounts of sugar and corn being used to produce ethanol causing concern that the security-based drive to cut foreign oil dependence is coming at too high of a cost, to both consumers and the climate. The International Food Policy Research Institute, for example, estimates that corn prices could rise as much as 25% by 2020 as a result of increased biofuel consumption. Clean Air Watch says renewable fuels can increase smog-causing pollutants like nitrogen oxide, while raising the ratio of ethanol in gasoline beyond 10% — Minnesota wants 20% — could damage car engines.

Lukoil’s ambitious plans to establish itself as a global heavyweight over the next decade could be running into trouble. Russia’s largest private-sector oil company is finding openings for non-state players dwindling at home, while overseas expansion is proving challenging, and presenting the company with some tricky decisions over whether to invest in countries such as Sudan and Cuba — tricky because of Lukoil’s exposure to the US, which has sanctions in place against both territories. Lukoil has a substantial retail business in the US, is part-owned by the country’s third biggest oil company ConocoPhillips, and has its shares traded on the New York Stock Exchange. But it has also been offered a stake in an upstream project in Sudan by state China National Petroleum Corp. (CNPC) in return for the Russian major’s agreement to waive its preemption rights to a 50% share in 72,000 barrel per day Kazakh producer Turgai Petroleum, which CNPC acquired when it bought Canadian-registered PetroKazakhstan for $4.2 billion in 2005. Lukoil holds the other 50%. Lukoil outlined plans in New York last year for capital spending of $100 billion between 2006 and 2016 aimed at doubling its production, refining capacity, and market capitalization to 4 million barrels of oil equivalent per day, 2 million b/d and $150 billion-$200 billion respectively (PIW Oct.23,p1).

Lukoil also seems to have changed its mind about processing future equity oil output from Venezuela at refineries in the US, where its strategic alliance with ConocoPhillips has so far failed to help it secure refining capacity, and may instead build a plant in Latin America — possibly in partnership with state Petroleos de Venezuela (PDV), and possibly in Cuba. Lukoil Overseas President Andrei Kuziyayev has refused to be specific about the location of the refinery, other than to say it wouldn’t be North America — a change of focus since Lukoil President Vagit Alekperov’s comments last year that the company wanted to process up to 200,000 b/d of its future Venezuelan output in the US. It could instead work with PDV — when Venezuelan President Hugo Chavez visited Moscow in June, he announced plans to build 13 refineries across Latin America and expressed interest in forming a joint venture with Russia to complete those plants. Possible sites could include Cuba, where PDV has already set up a joint venture with state counterpart Cupet to revive the Soviet-era Cienfuegos refinery (PIW Aug.13,p7).

Lukoil is set to sign an oil development contract in Venezuela for the Junin-3 block, pending verification of the acreage’s reserves. The Russian major is taking a minority 40% stake in the block, with PDV holding the remaining 60%, in line with the tougher terms Caracas is now imposing on foreign investors. In Saudi Arabia, Lukoil’s gas exploration efforts have had mixed results — its first $53 million well came up dry, but there have been more encouraging indications from its second. Lukoil’s upside from Saudi gas exploration would most likely come from liquids, since any gas would be sold on the domestic market at a significant discount to international prices, although the company’s most recent drilling update played down earlier announcements hinting that some condensate had been discovered (PIW Feb.26,p9).
Pertamina’s Ari Soemarno: Raising The Game

Having long trailed the likes of Chevron and Total as an oil and gas producer on its home turf in Indonesia, state oil firm Pertamina is striving to improve its game. In an interview in Jakarta, President and Chief Executive Ari Soemarno tells PIW that Pertamina intends to move further away from its government roots and become a more independent oil company, driven by competitive performance indicators and the pursuit of commercial profit.

Q. How far is Pertamina along its target of becoming a more proficient upstream player?
A. We are increasing our upstream budget for exploration this year. From our own funds, we are allocating $900 million, compared to $500 million last year and we will allocate a significant amount of funds next year. We are putting an emphasis on building joint ventures with reputable companies. This is something different from the past when we had many local [partnerships] due to a push by the government to develop local companies. But at the end of the day, this is a business that requires funds and technology. So in terms of developing local capabilities, [the government] should be developing Pertamina to not depend on somebody else. You can see how the Cepu Block was finally sold to Exxon Mobil — it will no longer be like that. It is going to be Pertamina and we have to find reputable and experienced partners like national oil companies and multinational corporations. Being an integrated oil and gas company, we have to put more emphasis on the upstream, which is the real bread and butter of an oil company. The downstream business gives us a lot of cash flow and creates a lot of revenue but margins are very thin. Upstream, we have the largest concession area in Indonesia and the government has allocated us the largest areas. We still receive special attention from the government to get more areas and participate in new areas with other partners. We see Indonesia still having a lot of potential in terms of reserves. It is natural we want to be an upstream player but in doing that, we have to look at our own resources. In terms of skill and knowledge, we still do not have sufficient skilled people. Upstream staff are very much in demand [and] we are losing people.

Q. Which oil companies are you talking to for new upstream partnerships?
A. We are working closely with Royal Shell Dutch in the upstream sector and are in the process of developing joint cooperation to explore in new areas in Indonesia. We are working on that and hope to conclude something by this year in the offshore and deep-sea areas. I cannot say how many blocks but they are huge areas in the frontier regions offshore southern Papua. Many people think it is a prospective area because it goes south towards Western Australia where the Masela, Bayu Undan, North West Shelf, Sunrise and Gorgon fields are located. Some people say it is a good belt and the sedimentary basin is somewhat connected. We would like to see if this is true. We are also in talks with Brazil’s Petrobras, [which is] experienced in deepwater operations. We would like to jump our expertise from onshore to offshore and to deep-sea. We are in talks with Thailand’s PTT for areas in Myanmar and Thailand and also for exchanging areas. We have done that with Malaysia’s Petronas and PetroVietnam before. Now we are in talks with PTT to do the same.

Q. Pertamina signed several upstream accords in the last two years, when will we see firm results?
A. We signed a memorandum of understanding with Russia’s Lukoil and are talking about swapping areas in Indonesia with their interests in the former Soviet Union like Azerbaijan or Kazakhstan. We are talking to South Korea’s SK Energy and Korea National Oil Co. for new areas and in Pertamina-owned areas. We have 140,000 square kilometers of concession areas and many of them are still under exploration. We are diligently talking at the moment to finalize these agreements but they are at a preparatory stage. This year will be identifying areas but I hope these undertakings can take place next year.

Q. Are there any updates on Pertamina’s Block 3 in Iraq’s Western Desert and other overseas assets?
A. We have no progress on Iraq. We are in discussions with several parties to jointly operate the block and are talking with Malaysia’s Petronas as they have an area adjacent to it. I just received a statement of interest from the Turkish national oil company and it is a good candidate due to its proximity. But it is difficult to find people to work there. We are still concentrating on exploration and seismic in Libya [Blocks 17-3 and 123-3 in the Sabratha and Sirte Basins], while we are seeking advice from the Sudanese government on how we can proceed [with Block 13] although we have already agreed on a joint venture with China National Petroleum Corp. for the offshore block.

Q. What is your take on investing in these politically risky overseas assets?
A. Many people say you are exposed to high risk when you invest in these countries. That may be true but if we go to a more stable country, the competition is higher as you are competing with other multinational corporations. We see more opportunities [in these areas] although it is more risky on some occasions. It may be risky today, but not by the time we find oil. We have to take that chance. In some cases, these countries provide privileges and are more considerate to national oil companies.

Q. Domestically, when can we expect first oil from the Cepu Block?
A. It depends on the availability of the export facility. That is what’s causing the bottleneck at the moment — the pipeline and the export facility. The problem [of clearing land to lay the pipeline] is increasing because of local [opposition]. We have to find a solution with the people there. We will start production in 2008 but output will not be much because the oil has to be channeled through the only existing pipeline from PetroChina’s Sukowati field. It has only limited capacity and is what’s holding back production to 10,000 b/d in 2008.

Q. What is latest on the Natuna D-Alpha Block with Exxon?
A. We are still waiting for a government decision on the Natuna undertaking.
Q. How are the economics of developing the sour Natuna gas?  
A. Natuna gas is a difficult gas. First, the quality of the gas requires huge costs and adequate technology. Second, the block is in a very remote location and requires huge investments to produce the gas. Recent calculations show that if the production sharing contract split is 40-60 in favor of the government, you are talking about a gas price at the wellhead of $15 per million Btu. But if there is a 50-50 split, the price would be lower. If the split is 55-45, then the price may be $7-$8/MMBtu — that’s okay and we could be in business. Whoever operates the area must consider the high cost to produce and purify the gas. If, hypothetically, Exxon’s contract is terminated and given to Pertamina — although it has not yet been decided — we will give the same economics. Everybody will come to the same figure — perhaps differing by one or two dollars — but it would be in the same ballpark. The government cannot force us to work on the block and subsidize the gas — no way.

Q. Is the solution bringing in more partners to share production costs and risks?  
A. Sharing the cost, yes. But the government has to decide if they want to develop it now or later. If [they want it] now, they have to have better terms on the PSC so the contractor, whoever it is, has attractive returns to develop the field. That is the key. We cannot subsidize the project — it has to be economic. We have to talk to the government and make them aware of that. We will try hard to convince them that at the end of the day, it is their decision. [But it is] not only about sharing the risks or investments. The question is, ‘Who is willing to buy the gas?’ We are talking with Petronas and PTT to be the gas buyers, while everyone else is saying they have experience with dealing with the high carbon dioxide content [in Natuna gas] — Statoil, Shell, Total and, of course, Exxon is saying the same. We will have to wait for the government to decide.

Q. What are the development options for the project?  
A. A pipeline to Malaysia, to Thailand and even LNG, where we can build the plant or we can supply the gas to Malaysia’s Bintulu LNG complex. But there are no plans at the moment because we are waiting on the government.

Q. What is the government doing about dwindling exports from the Bontang LNG facility?  
A. Chevron will do more exploration in Kalimantan. They said they would drill 50 wells this year. The key is in the deep-sea wells. The government is also more flexible now in terms of exporting LNG and has already given assurances it will agree to whichever gives better economics [selling LNG to the export versus domestic market]. That’s why they [Chevron] have started development in East Kalimantan again and are trying to find more gas. Total is also doing some exploration in their existing concession areas.

Q. Is there any chance of ramping up exports from the Bontang plant?  
A. If they find all the gas in the future, yes. We have already agreed on the extension of LNG trade with Japan beyond 2011 for about 10 years. At the moment, [volumes are] discussed at 3 million tons per year but there is a possibility that exports can be 10 million tons/yr although we have to confirm the gas. But Chevron needs to extend its PSC because it runs out around 2017. If they start production in 2011, they’ll only have three to four years before the expiry of their PSC so they will need to do something. Bontang doesn’t seem so bleak because there is around 1.5 Tcf to 2 Tcf offshore South Kalimantan and other potential gas reserves out there. But I don’t think they can resume the 20 million tons/yr we are doing now.

Q. How about the Arun LNG plant in Sumatra?  
A. It will still be producing until 2014. But there is no more gas there. We cannot see significant gas reserve to support production. Arun has done its service.

Q. Are there possibilities for new LNG projects in Indonesia?  
A. Yes, there is the Masela Block [held by] Japan’s Inpex and Pertamina’s Sulawesi LNG project where we are planning to build one LNG train. There is still potential for gas there and, if we are able to confirm reserves, we could produce more than 2 million tons/yr or [build] a second train. Everybody seems interested to join in Pertamina to explore in that area. A third train for the Tangguh project depends on the reserves. At the moment, they are not looking for LNG buyers [from a possible third train] as they are waiting to confirm remaining reserves of around 3 Tcf.

Q. Is Pertamina planning to build an LNG receiving terminal in Indonesia?  
A. Yes, we are discussing the possibility with Korea Gas because we have the expertise and knowledge in LNG plants, where we operate a terminal to ship the LNG. If somebody wants to build an LNG terminal in Java, I think we are in the best position to do it. Both PLN and PGN are users of gas [but] PGN is only a pipeline company and a distributor, and PLN is a gas user. If they want to build a terminal, they have to be able to supply the terminal. They know how to use the gas and pipe it but not how to run an LNG terminal. We do. We know that type of project. We are in a neutral position to supply both to PLN and PGN, and we have the expertise in LNG terminals.

Q. Does this mean the end of Indonesia’s plans for more domestic pipelines?  
A. A pipeline is dependent only on one source. If we build an LNG terminal, we can get gas from Kalimantan, Tangguh, Natuna or through imports [from abroad] without building pipelines. It is more flexible. If we are talking about a 2,000 kilometer pipeline compared to an LNG terminal, the project economics is just about balanced. But the versatility of an LNG terminal makes more sense. We don’t believe in the [proposed] East Kalimantan-Java pipeline.

Q. But are export-oriented LNG projects still viable when it is unclear whether the government wants to use more gas domestically?  
A. At the end of the day, it all depends on economics. If you find gas in Java, what is the opportunity there? We can only produce the gas and sell it domestically at a reasonable price which gives us reasonable returns — let’s say an internal rate of return of 15% to 20%. If the government forces us to sell for a return of less than 12%, we will not do it. The government has to think along these lines. Although Pertamina is still a government institution, we are pegged by key performance indicators and profits are our main objective. For us, economics is the foremost consideration.
**COUNTRIES**

**ALGERIA** — Gaz de France (GDF) is being tipped as a possible partner for the troubled Gassi Touil gas and LNG venture after state operator Sonatrach kicked Spanish companies Repsol YPF and Gas Natural off the project earlier this month (PIW Sep.10,p8). Citing diplomatic sources, the Spanish website El Confidencial said GDF’s entry was discussed during French President Nicolas Sarkozy’s visit to Algiers on Jul. 10. GDF remained coy, saying it would “study this project if it were offered.”

**ANGOLA** — Three newly designated ultra-deepwater blocks will feature in an offering of 10 exploration blocks later this year, the first since late 2005. Also likely to attract interest are three blocks in the deepwater, 19, 20 and 21, which lie to the south of BP-operated Block 18, where the 220,000 b/d Greater Plutonio development is the newest addition to Angolan capacity. The ultra-deep blocks — 46, 47 and 48 — lie to the west of Block 31, where BP is eyeing several years of decline due to maturity and a long-running conflict with guerillas but high hopes are vested in the lightly explored Caribbean offshore area (PIW Dec.18,p4).

**AUSTRALIA** — Oil Search has denied reports that China National Petroleum Corp. (CNPC) is launching a potential US$5 billion bid for the Papua New Guinea (PNG) producer. The South China Morning Post first reported the Chinese state giant was considering a bid, with European oil firms also interested. Most of the Sydney-based firm’s 26,000 boe/d of production comes from its mature PNG oil fields, but it also has upstream stakes in Egypt, Iraq, Libya and Yemen. Despite the Oil Search denials, PIW understands Chinese firms remain interested in the potential for LNG in PNG, where Oil Search is in talks with Exxon Mobil and BG Group over two separate LNG projects based on up to 25 Tcf of stranded gas (PIW Apr.16,p10).

**CANADA** — The two provinces of Alberta and Newfoundland and Labrador are riding the wave of rising resource nationalism to demand a bigger share of the proceeds from oil and gas projects. A government-backed panel in Alberta has recommended higher royalty rates — especially for oil sands projects — and introduced an oil sands tax linked to oil prices. The changes would raise the government’s take to 64% over the life of an oil sands project from today’s 47%. Conventional oil and natural gas projects would be subject to slightly higher royalty rates. The Newfoundland government has asserted the right to 25 Tcf of stranded gas (PIW Apr.16,p10).

**COLOMBIA** — BP and Brazil’s Petrobras were among the companies awarded exploration contracts for 13 offshore oil and gas exploration blocks in the Caribbean Sea announced by the National Hydrocarbons Agency last week. Block RC4 went to BP, Petrobras and Colombian state Ecopetrol and India’s ONGC took Block RC10 with Ecopetrol, which took 100% of another block. BP took Block RC5 while Block RC8 went to Petrobras, ONGC and Ecopetrol. Oil production is stabilizing at around 530,000 b/d after several years of decline due to maturity and long-running conflict with guerillas but high hopes are vested in the lightly explored Caribbean offshore area (PIW Dec.18,p4).
INDIA — Oil and Natural Gas Corp. (ONGC) will invest up to $5 billion over the next five to six years to develop the offshore KG-DWN-98/2 Block in the gas-rich Krishna-Godavari Basin. ONGC will submit a development plan for the block by early-2009 after firming up an appraisal plan to develop discoveries in the northern part of the block. ONGC said the gas fields could yield 12 MMcfd/15 MMcfd (420MMcfd-530 MMcfd) by 2012-13. The block’s former operator, UK explorer Cairn Energy, made three gas discoveries there between 2001 and 2002, selling the development rights to ONGC for $85 million in late 2003. ONGC went on to make its biggest deepwater strike there in December 2006, dubbed UD-1, which is now estimated to hold in-place reserves of 2.08 Tcf. The company has also roped in Norsk Hydro of Norway and Brazil’s state-controlled Petrobras as equity partners to develop the find (PIW Jul.9,p6).

JAPAN — The UAE’s International Petroleum Investment Co. (Ipic) will boost its downstream portfolio with the acquisition of a 20.85% stake in refiner Cosmo Oil for $576 million. Cosmo will issue 176 million new shares to Ipic and use the proceeds from the sale to invest in a new 25,000 b/d coking unit in Sakai. With the Ipic alliance, it will also likely boost its crude intake from the UAE. For Ipic, the stake in the 635,000 b/d refiner is an addition to existing stakes in South Korean refiner Hyundai Oilbank and two refineries in Pakistan (PIW Apr.16,p11). Ipic also has a 17.6% stake in Austria’s OMV and 64% of Austria-based Borealis, a petrochemical producer.

KAZAKHSTAN — Chevron’s Tengiz oil field development has come under attack in parliament for allegedly violating environmental laws as pressure mounts on foreign investors, most notably the Eini-led Kashagan project (PIW Sep.17,p4). Gani Kasymy, a member of the upper house, called for the Tengizchevroil (TCO) joint venture project to be suspended unless TCO deals with the huge stocks of sulfur that have built up as a byproduct of the production of sour Tengiz oil and gas. TCO groups operator Chevron (50%), Exxon Mobil (25%), state Kazmunaigas (20%) and Lukarco (5%), a joint venture of Lukoil and BP. Chevorn commented Sep. 20 that Tengizchevroil operates in an environmentally safe manner consistent with Kazakh laws and regulations and international industry practices. TCO currently produces around 300,000 b/d.

MEXICO — Hurricane Dean dropped 321,000 b/d off crude oil production in August, reducing it to 2,844 million b/d compared to the previous month’s 3.165 million b/d, while cutting natural gas liquids flows by 29,000 b/d and natural gas output by 296 MMcfd/d, according to state Pemex (PIW Aug.27,p9). Several days of precautionary shut-downs of offshore platforms in the Bay of Campeche reduced oil production by 315,000 b/d and associated offshore gas output by 284 MMcfd/d, accounting for nearly all of the aggregate decline. There was no reported damage to offshore facilities, however, and production is expected to recover in September.

RUSSIA — The Kara Sea in the Arctic Circle could have natural gas reserves of up to 15 Tcm (530 Tcf), according to Vnigaz, the exploration and research arm of state Gazprom. The whopping estimate is roughly double the potential seen in the Barents Sea, home to Gazprom’s 3.7 Tcm (130 Tcf) Shotokman project (PIW Sep.17,p7). Vnigaz estimates the Kara Sea holds 40% of the gas reserves of all the offshore zones it has studied so far. It estimates that both the Rusanovskoye acreage and the Leningradskoye fields have reserves of up to 4 Tcm each, while the offshore areas of the Kharasaveyskoye and Kruzenshternskoye Basins hold a combined reserves potential of up to 2.5 Tcm.

Well-Connected Winners In Equatorial Guinea

A mixed bag of state oil companies, oil traders and outfits with strong political links were the winners in Equatorial Guinea’s latest licensing round. Named on Sep. 14 after months of delays, they are not the star-studded cast of companies that President Teodoro Obiang Nguema had hoped to attract (PIW Jul.23,p5). The round was hotly contested by Nigerian companies, but most of them were weeded out for failing due diligence tests. All told, the Energy Ministry has invited six firms, including two partnerships, to negotiate production sharing contracts for seven blocks.

The highest profile newcomer is India’s Oil & Natural Gas Corp. (ONGC), which secured Blocks EG-12 and EG-13. The state firm has already bid in licensing rounds in neighboring Nigeria and is an investor in Nigeria’s Joint Development Zone with Sao Tome and Principe. The presence of Nigerian National Petroleum Corp. (NNPC), which is down for Block EG-14, is consistent with reforms designed to encourage the state firm to venture abroad and compete with international oil companies, but it also has a political complexion (PIW Aug.20,p3). Unusually, the bid is a joint offer with Afex Global and was submitted in the name of NNPC rather than its upstream arm, Nigeria Petroleum Development Corp.

Afex is linked to UK oil services company Terra Energy Services, which has a joint venture with GGPetrol, the state oil company of Equatorial Guinea that sells local seismic data to oil companies. Both Afex and Terra are privately-held and registered in Bermuda, but they have common shareholders, sources close to the bid tell PIW.

Africa-focused independent Ophir Energy, which is the operator of Block R, is down for Blocks EG-1 and EG-3. The firm is well placed due to the good relations with South Africa, whose intelligence services helped Equatorial Guinea thwart a planned coup in 2004, and due to the political influence of South African empowerment entrepreneur Tokyo Sexwale, whose Mvelaphanda Holdings has a strategic relationship with Ophir.

Block EG-7 went to the exploration arm of Swiss oil trader Glencore in tandem with Starc, an offshoot of London-based oil traders Stag Energy and Arcadia. Bermuda-registered Stag has strong local connections and has dominated the marketing of Equatorial Guinea’s crude for several years. Arcadia has links with the Driot family, which runs Stag, and has been marketing state crude since February. Glencore already has 25% stakes in Blocks I and O.
European Gas Oil Goes Over The Top

The tight supply of middle distillates in Northwest Europe has driven both futures and spot barge prices to record highs. The ICE October gas oil contract, which provides the benchmark for European middle distillate pricing, settled at $704.25/ton on Sep. 20 — a far cry from the $6 discount it recorded just a few months ago (PIW May 28, p.8). This swing of nearly $10 between two sweet crudes of very similar quality signals that their relationship is in less than robust health. In this case, the finger is pointed at landlocked WTI, which has no international exposure.

WTI gains its power from its liquid paper market and investors have, so far, been willing to put up with its physical ailments. Brent is considered to be much more in touch with the actual crude market. If that is the case, the recent price increase in WTI can be mostly ascribed to speculation.

However, that the market shook off its long-standing contango two months ago had much to do with physical shortages of supply — and they haven’t gone away. Importantly, though, these fears reflect US Midwest supply concerns, and do not signal an international supply crunch in the making. Brent contracts, supposedly telling a better story about global oil trading conditions, no longer trade in full backwardation.

A lot of the capital piling up in front of the price curve is ready to jump the moment that curve starts showing signs of weakness. Speculators bailing out could drag down oil prices considerably. And more money might jump if the global credit crunch spreads and affects global oil demand.

The front of the curve might be swelling, but the curve as a whole seems to be firmly anchored by the back, which remains around $70/ton. A futures curve is notoriously bad as a price forecaster, but the fact that it has stayed firmly in the middle of Opec’s unofficial new price band of $60-$80/ton might be more than just coincident.