SPECIAL REPORT ON WORLD NATURAL GAS PRICING

by Jeffrey Segal and Frank E Niering Jr

IT has arguably never been harder to name a "price" for internationally-traded natural gas than it is now. In the second half of the 1970s differentials, already wide, grew wider still. Schemes for deciding base prices or linking gas prices to those of alternative fuels or non-fuel indices increased in number and variety, while effective cohesion in policy-making continued to elude the major gas-exporting countries.

In recent months, it is true, moves have been made to remedy the situation, and to introduce not only higher prices all round but also an unusual degree of uniformity in price-fixing methods. However, the latest proposals for major reforms are based on such misguided assumptions about the nature of the market-place, and are burdened with such practical drawbacks, that they seem set to leave the pricing system almost as chaotic as it stands at present.

Reliable estimates of prices paid by importers is difficult to come by. Most border prices are either confidential or, when made public, tied in to such esoteric escalation formulae as to become meaningless. Studying importing countries' trade statistics, however, gives a fairly accurate idea of actual values, at least on a yearly basis (see Table 1), though some minor distortions are inevitable.

For example, the estimated prices paid by Eastern bloc countries are worked out on the basis of official exchange rates, though in fact variable barter rates are used. Prices paid in the West for Soviet gas are in practice underestimated, as there is often an element of cheap credit provided by the importers to finance the transmission system itself. Presenting the price in US dollars per million Btu gives rise to other inaccuracies, as non-accountable fluctuations both in exchange rates and Btu contents of specific gases may arise. And omitting small, short-term trades—spot movements of LNG tankers or intra-European pipeline flows between non-recognised suppliers and clients—may further devalue the data.

Broad conclusions

Some broad conclusions can be reached about 1975-79 prices, however. Firstly, the "average" price paid—such as can be determined—roughly doubles over the period. Secondly, and perhaps more significantly, prices remained low compared to those of crude oil; from an average of just under $1.00 million Btu in 1975 (equivalent to a barrel of crude at less than $6.00) to slightly over $2.00 last year ($12.00/bbl). Thirdly, the spread of prices actually grew; from $0.47-$2.07 in 1975 to $0.72-$3.65 in 1979. (These differentials are substantially greater than those for oil, though it should be pointed out that the high and low extremes are usually for small contract volumes.)

Fourthly, there is little uniformity among the prices obtained by the same exporter on different markets. The Netherlands (the world's biggest international supplier) realised cif prices ranging $1.25-$3.65 million Btu on five different markets last year. The USSR earned from $1.15 to $2.70, and the Algerians $1.15-$2.50. Some important buyers, though, only pay a limited range of prices regardless of source—for example, Japan, Belgium, France, Italy, West Germany and Spain.

Divergent arrangements

What the table also demonstrates is the total lack of a common pricing basis among exporters—even those within OPEC. There are divergences, for example, among LNG exporters as to whether the product is sold cif or cfr. Deliveries from Brunei to Japan, and from Algeria to the UK and the USA, go fob, while the Japanese pay an ex-vessel or dollar in Malaysia, Indonesia, and Abu Dhabi. Most contracts are on a long-term basis, with a 15- or 20-year maximum, though this, too, is far from the rule. Some deals operate on a "take-or-pay" system, while others do not specify minimum volumes. Some incorporate scheduled price rises at varying intervals; others move on a less predictable basis.

The pricing arrangements themselves can be either for an agreed flat rate, negotiable usually at yearly intervals; for a parity link with an alternative fuel; or, most often, a base-plus-automatic escalation formula. With the latter there can be big differences among the base prices, depending both on the exporter and the date of introduction, and in the index linkage. For example, in a wide-ranging renegotiation in 1975, Algeria officially introduced a uniform $1.30 fob base for its LNG customers. Even then, the French were allowed around $1.20, because of their financial backing of the Arzew liquefaction plant; El Paso, in the US, remained at $0.30 until May 1979, when their base rose to $1.25, with an initial 60 cents discount; and British Gas has stayed on a $1.50 base since the inception of its contract in 1964. Outside Algeria, base prices vary even more widely. The Libyans set theirs originally at fob parity with crude, for tax reference purposes, while Canada's was around $2.80 until last November. Escalation systems vary even more widely. Dutch gas, for instance, is linked to spot low-sulphur fuel oil prices at Rotterdam, though with a time-lag of 6-11 months and only to a maximum of 90%. The Algeria-UK formula, like the original El Paso deal, tied the rate of increase to steel prices and wage rises in different areas. Different baskets of currencies are used as a reference to keep prices from fluctuating too wildly against the dollar. And even where a link has been established with product prices—usually No 2 fuel oil (gas oil) or No 6 (residual)—proportions vary. The current Algeria-US system is for price changes in line with a 50% gas oil/50% residual formula, while in Europe Algeria gives a higher weighting to the cheaper No 6.

In comparison with the state of the crude oil market, even in today's relatively unsettled climate, the world gas price network appears to be illogical and effectively unworkable. OPEC, for the exporters, and the EEC, for the importers, have both called for uniformity and coherence in gas marketing. But there are many highly valid reasons why the two markets are so different.

No "world market"

In the first place, the actual scale of gas trading is tiny compared to that of crude. The total volume traded last year was some 180 billion cubic metres, equivalent in energy terms to only about 3 million b/d of crude, or less than 5% of world oil production. And neither exports nor reserves are concentrated in one single region, as they are in the Middle East for crude. About two-thirds of the total gas trade in fact comes from four exporters in quite different locations: the Netherlands, the USSR, Canada and Algeria.

But over and above the inability of any one producer or region to dominate gas sales, there is a fundamental difference between the export of gas and the export of crude: there is no "world market" as such for natural gas. Essentially, this stems from the high cost of putting export projects on stream. A new medium-sized LNG scheme is likely to cost upwards of $4 billion, while a recent study puts the investment needed for a project pipelining gas from the Arab Gulf to Europe at almost $6 billion.

A direct result of such enormous costs—and the long lead-times involved (frequently 10 years or more)—is that specific reserves have to...
### Table I

**WORLD: NATURAL GAS IMPORT PRICES 1975-1979**

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**General Notes:**

Figures in italics are estimates.

The table covers only significant long-term deliveries of gas by pipeline or LNG tanker. Minor intra-European movements within the pipeline grid are excluded. USSR exports to France are excluded, as these are "swapped" for Netherlands gas contracted for by Italy.

All prices quoted are in a cif basis, with the exception of USSR exports to Bulgaria, Czechoslovakia, East Germany, Poland and West Germany, which are fob.

The prices are derived primarily from importing countries trade statistics; conversion from national currencies to US$ has been made at average annual/monthly exchange rates as listed by the IMF, while conversion from volumes to thermal values has, when necessary, been made according to factors listed by the United Nations. In the case of the aforementioned Soviet exports, prices are derived from USSR export statistics. East European currency conversions have been made at rates listed by the United Nations. Where volumes or thermal values are not available in trade statistics, the prime source has been the United Nations' *Annual Bulletin of Gas Statistics for Europe*. Inconsistencies in thermal values and exchange rates may lead to marginal discrepancies between "official" and estimated actual landed prices as shown.

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be allotted to specific importers and markets. Particular tankers or pipeline systems are dedicated to particular trades, and unlike crude oil, there is very little interchangeability. Some LNG tankers, for instance, reportedly may be incompatible with the proposed Nigerian liquefaction project, while within the West European pipeline grid there is very restricted interchangeability between low-Btu and high-Btu gases. This inflexibility is enhanced by the small number of outlets and inlets for gas worldwide. The pipeline or tanker. Taking towards smaller differentials. at least at the Rapid oil spot market, which Canadian crude pricing system on to the ill-matched body outside of liquefied widespread) and substitutability and elasticity be allotted to stabilise. from there to Japan still make more sense of demand are both limited. With gas, the crude, transportation is cheap and flexible, characterised by the crude oil trade. and geographically, alternative on to the WestEurope,Japanandthe geomaticlines. ·

This inflexibility has been holding prolonged government-level talks with their European customers over their claim for a virtual doubling in rates — which were due, under the existing system, to go up to an average $2.50 in April. Only one of their 14 buyers has agreed a new price: Germany's Ruhrgas, which in August settled at a higher, undisclosed rate. The USSR has explicitly asked its Western clients for rises of around 50%, Libya, too, is demanding similar increases, as rising its job twice in recent months: from $1.62 to $3.20 in October, and again to $3.45 in January.

Algerian claims

The greatest interest, however, has focused on the claims of the Algerians, which first came to light in January and February. They have been demanding a price a $6.11 job from Gaz de France, which has two contracts with Sonatrach. The French monopoly accepted an increase to $2.40, but indicated that it is unwilling to pay more than $1.00 above that. Deliveries have been curtailed since March, though they are said to be picking up again.

Similar demands have been made of Algeria's American customers. Sonatrach has rejected outright the formerly agreed lump in El Faso's base price, first settled in May 1979, which would have meant an fob price of $1.95 for first-half 1980. The American company, unable to agree on a higher rate with the US government approval, had to stop taking deliveries as from April. Disturges, the second US importer, has also been informed of an Algerian price claim. Its fob rate was increased to $3.20 in July, up 58 cents, but the Algerians have rejected this as inadequate.

Sonatrach has now extended its demands to all its current customers, and threatens to jeopardise future contracts, too. The Panhandle project, due to start importing Algerian LNG into Lake Charles, Louisiana, next year, at some $3.25-$3.40 fob, is likely to be affected, while talks being held with prospective European buyers are at an impasse. Work has been halted on the 15.8 billion cubic LNG-3 liquefaction unit, which would have supplied much of the future contract volume, and the proposed Skidka East and Issers facilities also look unlikely now to be built.

OPEC policy on pricing

OPEC itself has now given its backing to the more radical price proposals. Its multi-nation gas committee has been working on the problem of gas price standardisation for over four years, and an official policy has now finally gelled. At three recent OPEC meetings — a gas group session at Algiers, the extraordinary OPEC meeting in Jeddah in May, and the summit in Algiers in June — the organisation has stated firmly that gas export prices should be “in line” with those of crude oil on a Btu basis.

Unfortunately, the statements have been intentionally vague on one crucial question — whether this pricing parity with crude should be on the gross landed or fob basis. The USSR whether parity prices should be set at the port of exit (fob). Algeria and Libya, in particular, had pushed for fob parity, while Abu Dhabi, for example, had strongly advocated parity on the basis of export.

Price parity with crude on a cif basis has already gained widespread acceptance, either as a bargaining plank in renegotiations or as a means of enhancing existing payments. The USSR and the Netherlands are reportedly using the cif parity formula in their current talks with buyers. The price of Ula gas, from the Norwegian North Sea, due to be delivered to WP Gelsenberg from 1983/84, has recently been set at cif parity with a basket of short-haul Middle East crude. And pipeline imports to the US, while under the US. This has been due to holding prolonged government-level talks with their European customers over their claim for a virtual doubling in rates — which were due, under the existing system, to go up to an average $2.50 in April. Only one of their 14 buyers has agreed a new price: Germany's Ruhrgas, which in August settled at a higher, undisclosed rate. The USSR has explicitly asked its Western clients for rises of around 50%, Libya, too, is demanding similar increases, as rising its job twice in recent months: from $1.62 to $3.20 in October, and again to $3.45 in January.

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OPEC itself has now given its backing to the more radical price proposals. Its multi-nation gas committee has been working on the problem of gas price standardisation for over four years, and an official policy has now finally gelled. At three recent OPEC meetings — a gas group session at Algiers, the extraordinary OPEC meeting in Jeddah in May, and the summit in Algiers in June — the organisation has stated firmly that gas export prices should be “in line” with those of crude oil on a Btu basis.
Instability

Despite this growing acceptance — on the part of both producers and consumers — of the concept of pricing gas at cif parity with crude, an element of instability has been introduced by the recent demands of Algeria, Libya and, in one particular case, Indonesia.

Since March the official Algerian claim has been that the disparity is unacceptable to the importers. Gas oil, for example, which competes with gas at the upper end of the market, is currently $5.50/million Btu in New York. Harbours and $6.50 in Rotterdam, while low-sulphur residual fuel oil fetches only $4.00 in Rotterdam and $4.25 in New York. Even adding additional costs for storage and contribution of the oil products still leaves them at a lower level than the proposed gas price.

Even if this gap could be overcome — if, somehow, the present low prices of products rose without the fib price of crude going up — tying gas prices to those of crude, either on a cif or an fob basis, would still suffer from a fundamental flaw. The problem is that crude and gas are valued according to totally opposite criteria.

The barrel of crude is basically priced according to its yield of light products, gasoline in particular. The latter reflects-structure, for example, is tied to production, sweet, light crudes for this purpose. This means that the lighter, high-gravity crudes command higher prices.

However, these high-gravity crudes also contain fewer Btu's/kilojoules. It is this low-gravity trend that has led to the expected fob price of gas. The buyer of a light crude is paying far more for Btu's than someone who buys a heavy crude.

Light-end yields

This is, of course, of little consequence for the crude buyer, who is interested in light-end yields rather than Bri. Natural gas, however, is valued almost entirely according to its Btu content. This is a way of accounting for differentials in quality (such levels of sulphur, inert gases, or, in the case of LNG, natural gas liquids) which tend to be accurately reflected in the heat-producing capacity of each individual gas.

Linking the price of a Bri-valued product to that of a gravity-valued product is itself illogical, and leads to sharp differentials in gas prices far wider than those in the crude market. For example, should Venezuela ever export gas, then on a crude parity basis the price linked to its benchmark 24° Tia Juana would work out at $4.78/fob at current prices. Though this is a heavy crude, and hence low-priced, it has a heavy Bri yield of some 6.07 million Btu's. Tying a natural gas price to 42° Ekofoik, on the other hand, would mean $6.58/fob. Ekofoik's low Bri yield of around 5.65 million Btu/b is more than offset by a very high per-Bri unit price.

Naturally the fob or cif price of gas would then depend on the choice of crude. Thus far, most exporters using systems like the one in piped low-sulphur crudes as the link (see Table III). Choosing instead a weighted basket of crudes would vary the price somewhat. But selecting a very high-gravity, high-priced crude would guarantee high prices, even though, in energy terms, there is no logic to such a link.

This explains why, for example, Indonesia has reportedly told Japan that it wishes to switch its "price point" from 34° Tim to 44° Attaka (now $34.25) or 52° North Sumatran ($34.75). The combination of high prices and low Bri contents would mean low gas prices of $6.12 and $6.42 respectively, even without taking into account Indonesian surcharges. If Algeria decided to take into account its $3.00/barrel exploration surcharges for crude oil, its cif prices would go higher still. This would increase the disparity at the end-users' point of sale, at least the $34.21/barrel price proposed for Saharan. The present demand is thought to be for $6.61.

There is a likelihood, too, of disputes arising in price negotiations over the Bri value to be actually fixed to a particular crude. Different methods of analysis, for example, can come up with widely differing values for the same oil.

But there is a further, even more profound objection to the link with crude, either on an fob or cif basis. Natural gas is not some alternative fuel, it does not compete with crude. Indeed, it does not compete with any single alternative fuel, the substitutes instead varying from one market to another.

Essentially gas is used for heat-producing purposes in stationary equipment. Crude, by contrast, is sought largely for its transportation end-products. The Africans at least recognise that their main aim is to boost their standard of living, but that their real aim is for a link with gas oil and ultimately with synthetic natural gas from coal. The crude link, they (and OPEC say, it is only a temporary expedient) desirous OPEC's commitment to crude parity.

Yet a tie to gas oil — assuring the mechanics of such an arrangement could ever be decided could be logical only for the upper end of the market. There are equally valid reasons for tying the price of gas to coal, the cheapest of its alternatives. Coal, after all, competes directly as a boiler fuel. Massive coal reserves are planned in both world trading and production, and a lowering of air pollution standards is predicted in some areas to accommodate this. Technological developments — for example, in dual gas-firing boilers, or in coal piping — make such a link even more appropriate, while the implementation of low-cost methods of coal gasification and liquefaction could further dent the ambitions of the gas exporters.

Exporters' case

Such arguments are unlikely to find much favour in OPEC or among other exporters seeking higher, rather than lower gas prices. They argue — albeit on slightly different lines — that export gas deserves to command higher prices even than alternative oil products, for five main reasons. Firstly, the cost of investment in an export project is far higher than for oil. Secondly, the nature of the long-term contract systems that are used for oil supplies, unlike oil. Thirdly, high prices will encourage the development of alternative and synthetic fuels and divert scarce oil and gas resources away from burning into what are often called "black hedges", for petrochemical feedstocks and transportation. Fourthly, gas already is used for "premium" purposes, where its clean and flexible properties are a distinct advantage over other commercial sectors. And fifthly, current "netbacks" (or profits) on gas are far too low by comparison with crude.

The first two reasons are essentially insuperable. Investment costs, though large, are...
amortised over the length of the contract and utilised into existing prices. Security of supply has been short of the illusion by the alternative of Iran in stopping exports to the USSR, and of Algeria in curtailing sales to France and suspending (though by mutual consent) exports to Eltho. The Netherlands, too, has threatened to cut off supplies to European consumers if no suitable agreement on pricing is reached. The third reason seems equally spurious: the notion that higher prices will stimulate production and gathering costs to 25 cents/million Btu; pipeline and transportation put on a further 25 cents/million Btu; and liquefaction (including (operation and amortised capital costs) adds a further 80 cents. The cost of liquefaction alone is likely to reach $1.10-$1.40 in new projects.

These high front-end costs apparently meant a loss of $290 million on Algerian LNG sales to the US up to December last year, according to the Algerian government. However, prices are set now even on a fob-Africa basis for the 50-55 cents/million Btu price with prices from $2.60-$3.40 fob. Algeria is netting back only “$1.30-$2.10—equivalent to $7.28-$11.76 per barrel of crude. It has threatened to give up on the exploitation of LNG if its profits do not improve, and either increase pipeline projects or, as other Middle Eastern countries have proposed, turn instead to domestic use of gas for industrial purposes.

Here, though, it should be pointed out that netbacks at the wellhead are lower still. A recent report prepared for an OPEC seminar on gas utilisation noted that the maximum cost of gas to ensure economic viability of different gas-consuming industries would vary from around $1.00 for sponge iron (and probably less for aluminium), up to $2.50 for methanol and $2.00-$3.00 for cement.

Costs paid off
Much of the substance of the “low netbacks” argument is similarly weak. Some of the liquefaction facilities and LNG tankers currently in use are approaching 20 years of age, for example, and their capital costs are virtually paid off. And while netbacks have certainly not grown as fast as the production of crude, since the first 1960s LNG contracts were set at base prices at or above fob crude parity, the cause is perhaps excessive profits on crude rather than limited profits on gas.

Even pricing gas at current fob parity with crude would not provide netbacks approaching those of crude itself. An Algerian fob price of $6.61 was quoted at one point of some $5.31 equivalent to $29.74 on a barrel of crude. To approach the current non-surcharge netback of over $36.00/b on Saharan Blend would require a gas price of over $37.11 fob — nearer to what the Algerians suggest is a reasonable gas oil parity price. Sonatrach has also tentatively suggested gas prices in line with those of electricity from new coal-fired or nuclear-fired stations, which would give a netback of 10-11 cents, close to what might reasonably be earned from a barrel of crude in perhaps two or three years time.

The Algerians, it seems, are virtually auctioning fuels for parity pricing of gas to the highest bidder. Indeed, the flaws in their case strengthen the feeling that the parity pricing issue is wholly subjective, and that producers' and consumers' individual needs far outweigh any objective rules. Recognising this, some recent deals have gone so far as to abandon almost the whole idea in favour of alternative linkages.

It has been reported, for example, that Nigeria proposes to sell LNG from its planned Bonny Island project at a cif base of $4.15-$4.25, depending on destination, escalating in line with an index based 55% on the cost of crude and product prices to importers and 45% on the level of industrial prices and wages.

The formula for Indonesian sales to Point Conception, in California, as approved by the Department of Energy, provided for a base of $1.25 fob with escalation tied half to Indonesian crude and half to US wholesale prices. The early Algerian sales contracts, it will be recalled, also had similar indexation provisions. The weaknesses in the radical exporters' case seem to have been grasped by the consumers, who in the main appear to be taking a hard line over price rises. All demands for fob parity pricing, for example, have been rejected by Japan, the US and current and future European buyers. In most cases Algeria has been forced to apply interim increases, giving cif valuations of around $3.00, and Japan has reportedly been exchanging information with American and West German importers, in an effort to build a buyers' bloc. And importers' countries' governments have stepped in to take negotiations over from the private sector.

This tough stance may moderate, however. It stems largely from the present surplus of crude and products on the world market, and the expectation that oil prices might in fact be rolled back. Underground gas stocks, too, are believed to be high following the mild Northern Hemisphere winter of 1979-80, further strengthening the buyers' hands. Total subterranean gas storage capacity worldwide is probably equivalent to more than 100 days' use.

Long-term outlook
The longer-term outlook for price patterns is affected by a great number of variables, which vary from one market to another. The pace of the development of alternative energy sources is the most important factor, for example, as is the application of pollution standards. The progress of the recession and its effects on currency relations could also be important, as could the importers' likely responses to price demands which will also depend on their financial involvement in the particular gas export project. Japan, for one, has large stakes in the area and the rate of return would be severely jeopardised by any failure to come to terms over prices.

Price deals will also reflect the extent of price regulation by importing countries' governments, and the role of the state itself in the power industry. And differing rates of dependence on imported gas will help determine the leverage a buyer might exert. In the US, for example, imported gas meets only 5-6% of the total energy requirements of the country in 1978, compared to 6.0% in Western Europe. The availability of domestic supplies is equally important, for instance, as very high for over 85% of its gas supplies and Western Europe 43%, but the US only for 6%.

Taking each major marketing region case by case gives some insight into future price trends. Eastern Europe is a special case. Politically and geographically, it is tied to the Soviet Union for supplies — a virtual captive market, with little negotiating muscle other than the price of its own exports to the USSR. The predominance of barter deals tends, in any event, to separate pricing trends here from those that develop elsewhere.

Japan seems to be the single most vulnerable market. Apart from the factors mentioned above, its overall dependence on imported energy is 98% of its total primary energy consumption. On the side of successive governments to adopt policies stressing diversification (both of products and sources) over and above short-term economic concerns. With Japan's role in the international oil market seen as growing rapidly — providing 7.2% of overall energy consumed in 1980 and 9.0% five years later. This policy seems to be taking hold at $3.00. Even with the current high level of LNG prices to Japan, and with the advent of gas, the glut of residual fuel oil, conversions away from fuel oil and into both coal and LNG are
proceeding purposefully in the industrial sector.

The cost of this self-imposed diversification requirement has traditionally been the world's highest gas import prices, aided perhaps by the lack of price regulation by the government (over and above intermittent "guidance" from the then Economic Ministry, now the Ministry of Industry and Trade). Several consortia of private utilities, serving generally a single municipal- ity, "roll-in" the high costs of LNG with those of other members of domestic natural gas and town gas available.

Many sources

The peculiar nature of the Japanese import system indicates that Japan now well capitalizes to the Indonesian demands on Forbes pricing, thus setting a precedent for the rest of the price-militant exporters. One card it has yet to play, however, is in the wider number of gas suppliers which it intends will make up its 1990 imports total. Apart from the four currently on the books, Malaysia, Malaya, Australia, Iran, Qatar, Bangladesh, BP has signed long-term deals with Algerian LNG. Two others have been approached for LNG sales. Any splits among exporters over pricing policy could only, therefore, be of benefit to Japan.

The Algerians therefore have little overall leverage over the authorities in Washington, who are currently handling the pricing talks. The US Energy Department and the Federal Energy Regulatory Commission in December 1978 to shut out two proposed import deals for Algerian LNG (by El Paso and Tenneco) primarily on economic grounds, with no rigorous policy is likely to be followed; there have been similar instances of government influence over Canadian, Mexican and Indonesian pricing proposals.

The Natural Gas Policy Act of 1978 also has provisions on imported gas pricing that greatly reduce the chances of Washington agreeing to inflated price guarantees. In the first place, the Act stipulates that industrial buyers of foreign gas will have to pay the full "incremental" cost, instead of being able, as before, to "roll-in" (or average out) the high cost with cheaper local sources.

In the second place, alternative fuel cost ceilings have been set which prevent in- cremental pricing from putting the delivered price of gas just above the price of appropriate domestic fuels. A US official leading the Algerian pricing talks has interpreted this as meaning 80% parity with No 6 fuel oil and 20% with No 2 as the outer limit, far below the Algerians' expectations. Again, despite the limited and gradual deregulation of domestic gas prices under the Act, it is still forecast that gas prices as a whole will remain some 50% below those of competing oil products until at least the end of the century, giving a still greater disincentive to yield to higher imported gas prices.

Capacity to switch

Perhaps the most important bargaining counter held by the US, however, is its flexibility in switching from gas to substitute fuels when the price gets too high. This was vividly demonstrated by the economic cutback in offshore from Canada after the price rose to $4.47 in February. April imports, for example, were 34% down on the previous year as buyers moved over to oil. In fact, Canada decided to forego an indicated rise to around $5.10 due on 1st October.

Western Europe falls between Japan and the US in its ability to withstand price demands. Currently only a limited supply enters the region from outside suppliers; 16 billion cu mettres/yr from the USSR, 5 billion from Algeria and 3 billion from Libya. That makes up less than one-tenth of total gas consumption. However, reliance on outside sources is planned to grow sharply. Within the EEC, imports from non-OPEC suppliers are seen, as rising to meet roughly half total demand by 1990, compared to just over 20% last year.

Obviously the level of dependence varies from country to country. The UK, having recently approved a North Sea gas-gathering system, is now virtually immune to pressure from the Algerians in talks now being held on renewal of the British Gas-LNG contract. France, on the other hand, is already dependent on Algeria for one-eighth of its gas supplies. It is in a less secure position and may be more inclined to accede to Sonatrach's demand, if only because even Algerian gas is relatively more secure than the Middle East oil it replaces.

For Europe as a whole, the prospects for assured and moderately priced gas supplies look brighter now than they did at the turn of the year. Then, the decision by Iran to scrap the IGAT II swap deal — which would have provided the West with 13 billion cu mettres/yr of Iranian gas and Western Europe with 11 billion of Soviet gas — had introduced an element of considerable uncertainty and the prospect of a major shortfall by the late-1980s. And Algerian threats to abandon LNG, coupled with Sonatrach's uncompromising posture in talks with prospective buyers in Europe, cast a shadow over some 250 billion cu mettres/yr from Algeria alone that could be supplied by LNG.

Italy and on to Spain, which could carry some 10 billion to Spain alone and perhaps double that if the route were to be extended into Northwestern Europe.

It is expected, however, that the USSR is talking of pricing its gas to the West at cif parity with light, rather than heavy, crudes. The Algerian deal is expected to give relatively low-cost LNG supplies, while any Cameroun project would be favourably inclined towards France, which would be likely to make a major financial investment.

The Algerians are anxious not only for a bigger share in the western European market, but also for an increase in worldwide consumption. If the Europeans are not encouraged by the Algiers' proposals, the Algerians would again be anxious to join the IGAT II scheme for LNG supplies, while any Cameroun project would be favourably inclined towards France, which would be likely to make a major financial investment.

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Conclusion

Despite growing price aggressiveness on the part of several OPEC countries, gas being produced from their fields continues to be at a premium, despite an earlier Laussine, former vice-president of Sonatrach and now a private consultant, estimates that two-thirds of the 200 billion cu mettres available for export to Europe is likely to be sold by Algeria, and perhaps by Algeria alone which is currently handling the pricing talks. Although Algeria and Libya now have a joint plan for the export of Algerian and Libyan gas, the price could not be at a low enough level to compete with other sources.

The Algiers' price is expected to be at a lower level, but it is not clear how this will affect the European market. If the Western Europeans are not willing to pay the price, the Algerians may be forced to reconsider their plans.

The Algerians are in a strong position to negotiate a deal with the Europeans, but it is not clear how much they will be willing to accept. If the price is too high, the Western Europeans may be forced to look elsewhere for their gas supplies.

With 41% of proven world gas reserves and 18% of the world's proven gas reserves, Algeria is in a strong position to negotiate a deal with the Europeans. If the price is too high, the Western Europeans may be forced to look elsewhere for their gas supplies.

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Nigeria presses claim for reduced state oil sales

The government is seeking to recover a total of some 80 million barrels of oil from Shell, Gulf and Mobil, the three largest producers, to “compensate” the state oil company for its reduced liftings during periods of oil surplus over the years 1975-78. The move, embodied in a White Paper, follows from the publication of the report of a judicial tribunal set up to investigate the apparent loss of oil revenues totalling Naira 2.5 billion (about $50 million), which in turn stemmed from the auditing of the Nigerian National Petroleum Corporation’s books last year, prior to the return to civilian rule in October. It was the first time that the books had been audited since 1975.

The tribunal, headed by Mr Ayo Irkefe, found that no money was missing, but discovered that actual government revenues for some years were substantially less than theoretical revenues due to NNPC’s inability to sell its full equity share (55%, up to July last year) of production in times of surplus. Some of NNPC’s entitlement had accordingly been left in the ground, while the oil companies continued to lift their full equity shares of the government-determined “allowable” production ceilings. In the short term this practice prevented a slump in government revenues by maintaining the level of royalty and petroleum production tax “take”, but it resulted in the companies’ share of actual production exceeding 45%, while of the reserves in any given field the government received less than 55%.

The tribunal determined that NNPC was unable to sell a total of 152,952,104 barrels of crude out of its entitlement from Shell, Gulf and Mobil fields during the years 1975-78, and pressed the government to “recover” that volume from the three companies. The government, however, appears likely to use the actual production level, as opposed to the “allowable” level, as the basis for calculating its 55% entitlement, in which case the amount to be claimed is estimated at some 80,000 barrels to be obtained to recover the oil over a period of several years out of the three companies’ equity entitlements of (at the present 2.2 million b/d production rate) 255,000 b/d (Shell), 145,000 b/d (Gulf) and 85,000 b/d (Mobil), the tribunal recommending that the companies identify wells which will be assigned to NNPC until the appropriate volumes have been lifted. The tribunal also urged the government to recover from the three companies part of the NNPC’s share of operating costs for the years concerned, which totalled Naira 495.5 million (about $890 million).

The recommendations of the tribunal came as a surprise to the oil companies, who were confident that they had been operating their participation agreements correctly. Oilmen commented that they were being penalised for complying with government pressure to continue to lift their full entitlement in times of surplus, and that the surplus was often a result of unrealistically high prices — which were fixed by the government. The government’s move amounts to a change in their participation agreements, backdated five years, and — at variance with OPEC’s attempts to boost its access to final markets — appears to acknowledge continued reliance on the oil companies as sellers, as well as producers, of Nigeria’s crude.

At the present nominal profit margin on equity production of 80 cents/barrel, the 80 million barrels claimed will cost the three companies some $20 million, allowing for the government’s equity share (now 80% in the case of Shell and 60% for other major producers) which would have been deducted when it was eventually lifted. But its value to the government at current prices will be over $2.800 million (after allowing for production costs) — more than twice the revenue which would have derived if the oil had been lifted in 1975-78.

A positive outcome of the affair will be a speeding up of the government’s reorganisation plans for NNPC, which was criticised by the Lishuwa for its wholly inadequate financial and production records and other management deficiencies. Its chairman (Mr A K Hart) and managing director (Chief F R A Marinho) are still suspended. The tribunal also recommended that Ashland’s production sharing concession be renegotiated to secure a larger state share, and suggested that present 30 and 60 days’ credit periods for crude oil sales be shortened.

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