Notebook

Notebook provides data not easily found elsewhere, background descriptions of important aspects of the energy system and reports on new developments. Contributions are invited.

The Decline of Natural Monopolies in the Energy Sector

GARRY E. VOLLANS

Introduction

For most of the twentieth century, economic activity within the energy sector of industrial economies has been characterized by a significant presence of natural monopolies, particularly with respect to the transport of energy commodities. Examples would include electricity and natural gas transmission and distribution, oil pipelines and electricity generation. A number of rationales have been developed to explain this *natural* phenomenon: large initial capital costs; generally declining costs with higher output; technological economies of scale; and economies of scope over market areas (Kahn, 1988). While not all reasons would necessarily apply in each case, they were certainly important and pervasive. For the most part, governments in developed economies have resorted to either regulation of price and entry or state enterprises or both to avoid the potential abuse of monopoly power and destructive competition, and always motivated

Garry Vollans is a consultant on energy and regulatory affairs.

by a concern for the *public interest*.

Even more pervasive is the criticism of natural monopoly regulation: either too much or too little; inappropriate to the task; inefficient; unresponsive; regulatory capture; biased, to name a few. Since regulation is part of the political process, perhaps such criticism is inevitable. Many attempts have been made to apply some structure to the continuing discussion. The following is particularly to the point:

> If these criticisms are accepted, we are left with two alternative diagnoses of the basic problem with current regulatory practice: the economic view that it fails to enhance efficient resource use, and the political view that it fails to respond to legitimate interest group pressures. There correspond two opposed implicit assertions of the appropriate objectives of regulation, particularly when it is used to control natural monopolies. The economic conception of regulatory failure implies that regulation should be primarily concerned with attaining allocative efficiency, while the political conception implies that regulation should strike an appropriate balance among all relevant interests and thus, indirectly, among all competing social goals (Schmalensee, 1979, p.13).

In practice, regulatory agencies normally try to achieve both objectives simultaneously with, not surprisingly, only limited success. Even if regulatory agencies were to attempt to focus on allocative efficiency, vested interest groups can be expected to intervene in the process to promote their respective interests.

Politicians have also often found it convenient to deflect such groups towards the regulatory forum (or to the state enterprises created to run the natural monopoly) and thereby avoid a direct confrontation with interest groups. The use of state enterprises as opposed to regulated private franchises reflects both political and economic forces in play at the time the organization was set up. Moreover, the wide-spread use of energy commodities throughout the economy lends some credence to the tendency to treat them as strategic commodities in the security of supply sense or as potential instruments to support economic and social policy for a period of time. In short, there are many forces in play which serve to maintain the regulatory status quo, even among those regulated.

In this paper, the historical context for natural monopoly regulation in the energy sector will be reviewed with a view to identifying some of the relevant market factors which have evolved over time leading to a potentially modified role for and impact of natural monopoly regulation. The perspective is that of Kahn (1981, p. 66) expressed in a comment on a paper on regulation:

> If I were asked to offer one single piece of advice to would-be regulators, on the basis of my own experience, it is that as they perform their *every single* regulatory action they ask themselves: 'Why am I doing this? Is it really necessary?'

Some current market and technological developments will be discussed as they pertain to the regulated energy industries to identify potential economies in the regulatory process itself and the implications for the achievement of social goals. More specifically, would the economic, technical and political forces which led to natural monopoly regulation over the past century still lead to the institutional arrangements in place today?

Historical Backdrop

Energy consumption in its various forms, whether direct or embodied in other commodities, is pervasive in modern industrial economies.[1] The rate of market penetration/loss has varied among economies based upon resource endowment, location, relative prices and policy initiatives but there remain many common patterns reflecting shared technological developments and market integration. Figure 1, based on Canadian data, portrays indexes of real output for over half a century for the total economy, gas distribution and the integrated electric power industries.

1/ At various times and places, this fact has and continues to be used as a rationale for strategic commodity regulation of one or more energy forms, whether for defense, social or industrial policy reasons. A discussion of this perspective is beyond the scope of this paper.

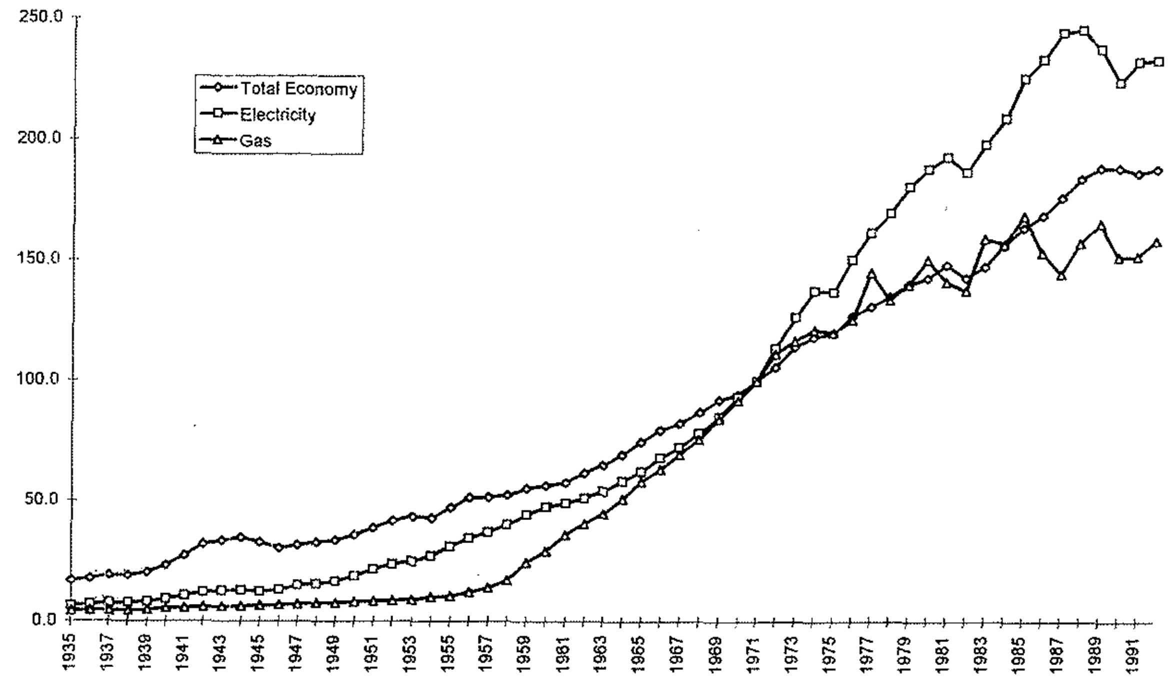

Figure 1: Canadian Indexes of Real Domestic Product (1971=100)

In many respects, both gas and electricity would appear to follow the Schumpeterian pattern of economic development of a new technology: a relatively low rate of growth initially, as the technology gains acceptance; a very rapid period of growth reflecting market penetration, substitution and the development of new uses while costs increase slower than the general price level; and then a tapering off period reflecting maturity in terms of market acceptance and growth based on general economic activity (Schumpeter, 1962). The downstream natural gas distribution industry depicted by these data took off in the mid-1950s, fed by expanded transcontinental pipelines into central Canada, tapering off to about the same rate as the economy in the 1970s and more recently, levelling off to a rate of growth less than that for the total economy. The rapid period of growth for the integrated electric power industry started earlier and lasted longer than that for natural gas but has also tapered off dramatically in recent years. The rate of growth in the late 1970s and early 1980s was sustained at relatively high levels by the completion of major hydro and nuclear facilities with significant net exports.

Figure 2 provides a more detailed Canadian perspective since 1960 based upon total final consumption (TFC).[2] While growth in total energy TFC roughly matched economic growth over the first two decades, it has levelled off since 1980. Both gas and electricity gained market share over the entire period, with gas jumping from 10% in 1960 to 26% at the end of the period while electricity rose from 13 to 23%.[3] Growth rates for both gas and electricity TFC significantly exceeded that for the total economy over the first two decades, but they were all roughly equal over the last 12 years, indicating mature industries in the Schumpeterian sense.

2/ The source for Figures 2 and 3 is *Energy Balances of OECD Countries*, an IEA/OECD publication. Total final consumption (TFC) represents energy used in its final form by end-use sectors (i.e., net of transformation from one form of energy to another, losses and uses in the energy production and delivery systems, and net exports). The item GAS (TFC) adj includes gas used to generate electricity.

3/ Energy market shares and compound annual growth rates for all countries of the Group of Seven are presented in Tables I and II of the Appendix.

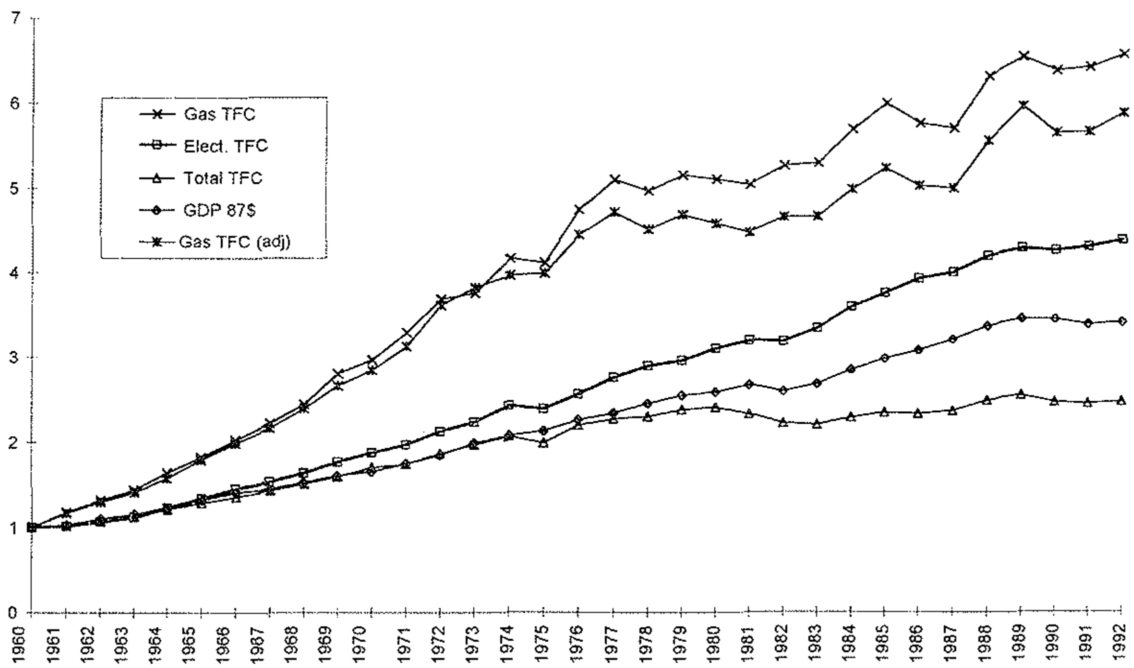

Figure 2: Energy GDP Indexes – Canada (1960=1)

As Figure 3 indicates, the pattern of development in the United States was similiar to that for Canada with the difference that the natural gas market matured somewhat earlier. Aside from an artificial jump in the late 1960s and early 1970s caused by wellhead price regulation of production for interstate markets, natural gas TFC has increased almost lockstep with total energy TFC over the entire period. Growth in electricity TFC surpassed that for both total energy and gas over the entire period, increasing market share in the process from 7 to 17%. The rate of growth of electricity TFC also consistently surpassed that for the entire economy, although the differential narrowed from nearly double over the 1960s to only marginally higher by the 1980s. While relative price shifts have had a role to play in explaining growth patterns, it would nevertheless appear that both gas and electricity growth rates are consistent with the mature industry concept.

The energy markets of the four European members of the Group of Seven industrial economies have generally portrayed similar growth patterns over the entire period. Having gained pipeline access to supplies somewhat later than major consumption centres in North America, rates of growth in the northern European countries of gas TFC have nevertheless approximated those for the economy by the early 1990s. In Italy, by contrast, gas continues to make significant market penetration. While electricity consumption also grew much faster than the entire economy over the 1960s and 1970s, the rates of growth were roughly equal over the rest of the period. The pattern was similar on an individual country basis, although the rate of growth in France and Italy has not tapered off as quickly as in Germany and the UK.

Growth patterns in Japan differed somewhat from the other members of the group but there are also many similarities. Both gas and electricity TFC grew faster than the economy over the entire period but the rate of growth over the latter third of the period covered was marginally lower than that for the total economy. Despite lack of access to relatively lower cost pipeline supplies, natural gas in Japan has managed to increase its market share based upon relatively high cost imported LNG sup-

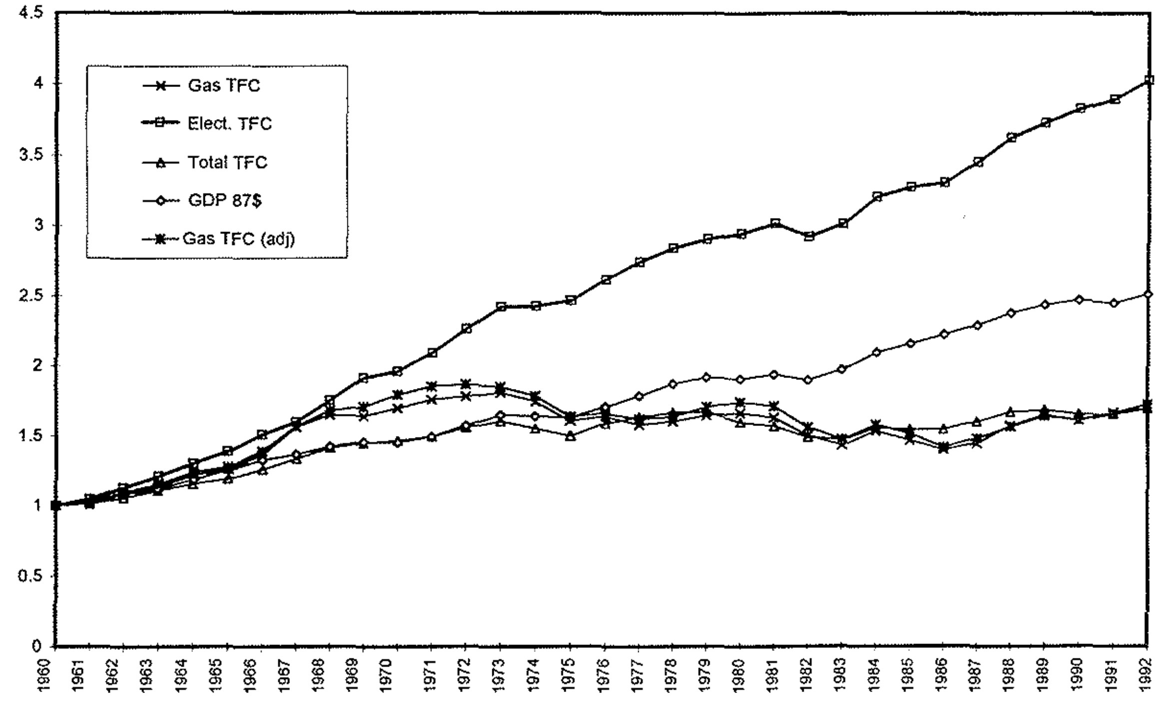

Figure 3: Energy GDP Indexes – US (1960=1)

plies. While the rate of growth in gas TFC has consistently exceeded that for the total economy over the entire period (6.9 vs 5.9%), one might expect these rates to converge consistent with the mature industry concept unless technological supply breakthroughs develop such as pipeline access to Siberian gas supplies.

To summarize, the gas and electricity industries in each country have developed at rates reflecting the indigenous resource base and relative supply costs. Despite the influence of direct policy initiatives such as natural gas wellhead price controls in the US and nuclear technology support in France, the underlying trends for gas and electricity in all of the economies in the Group of Seven exhibit a tendency towards rates of growth at or below that for the economy as a whole, in short, classic mature industries.

The three main energy sources in these economies have developed complex and capital-intensive supply, transportation and distribution systems with varying degrees of vertical integration. As mature industries, there is an on-going competition for market share on an interfuel basis, with nonconventional sources of supply and in the technologies employed to transform and use energy. Furthermore, new and improved financial instruments, supported by rapid developments in transaction costs and methods of information capture, compilation and management are serving to redefine the boundaries of the various "natural monopolies" in the energy sector of industrial economies.

The role of governments in the energy sector has also evolved over the past century. Local distribution franchises, whether privately or publicly owned, involved municipal control and overview of the "contract" to provide a service via public rights-of-way. Regulatory overview in turn provided an independent means to continuously modify this long-term contractual relationship to reflect changing circumstances, to arbitrate property disputes (e.g., expropriation), and to preclude opportunistic behaviour by the monopolies created (Priest, 1993). Public ownership evolved in many jurisdictions, serving to internalize this contractual relationship and, arguably, providing easier and cheaper access to the capital required to build the large infrastructure required and a direct instrument of public policy. In either case, the symbiotic relationship provided consumers with access to the benefits of economies of scale while providing developers (and their financiers) with the assurance that the necessary infrastructure would not be stranded by opportunistic entry into the market during the rapid growth phase. The next section of this paper examines each natural monopoly market in more detail with a view to better understanding the institutional arrangements that have evolved in order to identify those that might have become superfluous in a mature industry context.

The Rise of Natural Monopolies

Electricity

Companies marketing electricity often started with one source of power for a rather small local lighting market. It was soon evident that running two distribution lines down the same street did not make sense, leading to the development of local monopolies through mergers and municipal franchises, a classic natural monopoly to capture economies of scale. Once the distribution system was in place, the incremental cost of infill customers was relatively low and demand continued to grow as appliance and equipment manufacturers developed new uses for electricity at little or no marketing cost to the electrical utility. The displacement of manual labour in homes, mechanical power drives in factories (steam and water) and use of refrigeration and freezers in the food distribution system are all examples of changes which led to significant growth in the demand for electricity. The process continues today, for example home entertainment centres and personal computers on every desk, both fairly recent developments, but the pace of market growth may have tapered off in response to higher relative prices and market saturation.

In the generation of electrical power, there have also been significant technological developments leading to ever greater economies of scale in conventional thermal power generation, although most of the technological gains were introduced and captured by equipment suppliers and engineering design firms (Joskow and Schmalensee, 1983). Hydro facilities are by their nature restricted locationally and have high initial fixed costs, leading to economies of scale over much of their potential output range. Gas turbines on the other hand face relatively high fuel and other operating costs and are therefore used primarily to meet peak load needs. Large thermal power stations (steam-electric) fall in the intermediate area in terms of initial capital costs and operating costs. Depending upon their age, reliability, operating costs and other factors, these units may be used for baseload, peaking or for stand-by reserve requirements. There are at least three types of scale economies in power generation: at the unit level, at the plant level and at the firm level (Joskow and Schmalensee, 1983). Economies at the unit level relate to such factors as engineering design optimization, while plant level economies reflect factors such as common services/skills, common site, etc. Firm level economies are associated with multiplant construction and operation factors such as management and load balancing. As long as demand/load was growing fairly rapidly, as it appears to have done during most of the twentieth century, capturing potential economies was facilitated and in the process enhanced by the feedback from the lower relative average prices arising from these economies.

Another important area for economies and technological improvement has been in transmission and coordination of electrical power distribution. Extra-high voltage AC transmission and more recently high voltage direct current both reduced transmission cost from lower cost sites and permitted more interconnections of supply and distribution systems. These technological developments were important in their own right in lowering transmission costs but they also permitted additional economies in system coordination. On an isolated system, say an island, a generation system will minimize short-run costs where the marginal costs of all operating units are equal after adjusting for line losses (Pechman, 1993). This state is referred to as the system lambda by power engineers. Where two island systems are operating at two different lambdas, the total cost of operating both systems can be lowered, providing adequate transmission facilities are in place, by equating the two lambdas through an exchange of power, also known as economy interchanges (Joskow and Schmalensee, 1983).

Transmission across a third system is known as wheeling and often involves a complex set of calculations and negotiations to arrive at both an economically efficient and mutually agreeable price for the service (Kelly, et al., 1987). Nevertheless, there can be economies to be gained for all three parties, which have led to power pools and other institutional arrangements. Given the vagaries of demand, power dispatchers must constantly monitor and fine-tune flows over the system grid to ensure reliable and least-cost short-term supply. Prices for the transmission costs of short-term flows can be determined after-the-fact without interfering with the existing system dispatch process which serves to reinforce least-cost decisions by system dispatchers (Hogan, 1989).

Another closely related economy is in system reliability and the lowered cost of system reserves to meet load imbalances. This latter economy might be considered an economy of scope where the variations in demand peaks and troughs have a greater probability of offsetting one another across a wider group of consumers. There are also costs associated with more system interconnections in terms of information sharing and loss of control to the pooling authority but the continuing growth in the scope of regional power grids seems to indicate that the incremental benefits exceed the costs involved. On the other hand, the very complexity of the system may make the negotiations associated with the integration of independent power generators into the system more difficult, particularly where demand growth is slowing.

Within the area of electricity distribution, there has been little change to the principles of power on demand and reliability of supply for decades, despite dramatically different incremental costs over the time of day, season, day of week, location, etc. and costs to customers of supply interruptions. Where the latter are particularly costly, such as hospital intensive care units, customers provide their own back-up. Where costs are lower, customers provide their own insurance for damages incurred. While economists have for decades bemoaned the fact that electricity prices bear little resemblance to marginal costs (Baumol and Bradford, 1970), the cost of metering, tradition and other practical considerations have precluded marginal cost pricing with a few notable exceptions such as peak load pricing for large industrial consumers in North America and various time-of-use pricing schemes in European jurisdictions. More commonly, declining block structures are utilized, especially for residential service. While this type of rate structure partly reflects the fixed costs associated with a connection to the distribution system, the marginal cost perceived by customers is likely to bear little resemblance to the marginal supply cost, particularly during peak demand periods. More probably, the marginal price will be too high during off-peak periods and too low during peak periods. While moral suasion is often used by utilities to encourage customers to switch their peak demand to off-peak periods, such cajolery is unlikely to have a significant impact on demand.

One notable exception to the foregoing relates to interruptible rates. Typically, a large industrial customer with back-up facilities or flexible demand can negotiate very attractive prices, subject to interruption with notification, providing the utility with additional flexibility and a market for off-peak energy, and the customer with lower energy costs. While the mutual benefits are obvious, there are also social economies in terms of an improved utilization of capacity in place. Interruptible rates can also be viewed as a partial unbundling of service provided, in effect breaking out the cost of supply reliability from the cost of transport and the power supplied. The customer benefits from lower energy costs but is subject to higher insurance costs, whether financial or real in the form of backup facilities. Utility shareholders and/or core customers benefit from higher profits and/or lower prices to the extent that fixed assets are more fully utilized.

Natural Gas

Gas distribution systems initially followed a development pattern similar to that of electricity based upon a local source of manufactured or natural gas. Street lighting was once an important market with the same natural monopoly forces in play in terms of the obviously higher costs of maintaining overlapping distribution lines and the economies of scale associated with attaching infill customers once the system was in place. Demand growth was somewhat slower, based in part on the convenience and cleanliness advantages over coal for space heating, offset by the direct competition from oil products for this market and a lower derived demand from new applications developed by equipment suppliers as compared to electricity.

On the supply side, the development of the natural gas industry was to a large extent the byproduct of the exploration for crude oil. Natural gas deposits were often discovered during the search for crude oil, or gas was produced in association with crude oil. Markets expanded from these supply sources based upon lower relative prices and subsequently through the development of transmission technology, particularly large diameter, high pressure pipeline systems. In the United States, during the decade following the second world war, there was a great deal of large diameter, long distance gas transmission capacity built or converted from oil use (Teece, 1990). In Europe, supplies from North Africa, the North Sea, the Middle East and the former Soviet Union were linked to consuming regions somewhat later. More recently, liquified natural gas (LNG) transported by ships has contributed to the supply system, particularly in Japan.

In contrast to electricity, the production, transport and distribution functions have not been integrated on an ownership basis, but rather on a contractual basis among the various segments. This development may reflect differences in transaction costs, such as the cost of negotiating, monitoring, and enforcing contracts in a highly complex and variable set of circumstances. While many characteristics of the two systems are similar, such as asset specificity and demand uncertainty, natural gas can be stored in underground reservoirs, as LNG and as pipeline "linepack" under higher compression, partially offsetting demand fluctuations and supply interruptions. Both industries have relied upon interruptible sales contracts and surplus capacity to offset demand fluctuations. More recently, demand side management (DSM) techniques have been evaluated as another tool to level demand fluctuations and to improve system utilization.

The post world war II development of natural gas transmission systems in North America and Europe has been regulated by both financial institutions (to protect their investments) and governments on the basis of long-term supply contracts to mitigate the risk associated with very costly and highly specific assets. In effect, functional integration through contracts with regulatory oversight precluded the need for vertical integration through ownership (Teece, 1990). In particular, firm contracts with "take-or-pay" provisions both upstream and downstream provided assurance that the facilities would be used and paid for. Now that the system in North America is largely in place (and the initial debt retired), expansion has become more incremental through looping of existing lines and additional compression, while the merchant function that pipelines once played has been virtually eliminated. Independent aggregators and brokers are playing a more important role with the pipelines operating as common carriers.

Furthermore, spot and futures markets are developing based on trading hubs, permitting producers, distributers and consumers a greater role in hedging risks of price and demand fluctuations, flexibility in supply arrangements and more market transparency. In particular, the length of supply contracts has been shortened considerably, and larger consumers are taking a more active role in purchasing gas and arranging for its transport. Electronic bulletin boards and trading are also developing, as the short-term market grows in importance along with arbitrage in the form of theoretical backhauls to reduce transport costs. In 1994, the three largest gas transmission pipelines in Canada set up a joint venture to operate an electronic bulletin board, which will permit one stop shopping for natural gas marketers and shippers. Developments of this nature facilitate access to and release of pipeline capacity, a type of capacity brokering in a secondary market using the price mechanism to assign released capacity to the potential customer which places the highest value on it.

As the market has evolved, price and entry regulation of natural gas transmission systems has also evolved, although not necessarily at the same pace. Unbundling the gas transported from the cost of transporting it left the negotiation of gas prices to producers, brokers and consumers. Pipeline tariffs are still subject to cost-of-service type regulation for the most part, but some system expansions are subjecting the pipeline shareholders to additional risk if the facilities are underutilized. This approach creates problems in terms of access to existing capacity which is typically underpriced relative to new capacity. Traditionally, the costs of expansions have been "rolled in" or averaged with the historical accounting costs of the existing system. This system benefits all where average costs are falling with increased output. Even where costs are constant, or rising slightly, as long as current customers were given an opportunity to avail themselves of the additional capacity, they normally accepted the usually small associated increase in tariffs. Once average costs start to rise and incremental capacity is priced on an incremental basis, shippers with access to capacity on the "old" system enjoy a measurable economic rent and rationing problems are created for any space that might become available if it cannot be brokered at a market-determined price.

As gas transmission companies got out of the gas merchant business, local distribution companies (LDCs) or gas utilities picked up more responsibility for gas supply. Since they are typically still subject to cost-of-service price regulation, they became subject to more risk if the regulator deemed that the gas purchase price were "imprudent." Further, with unbundling, some of their customers arranged their own gas supply and paid the LDC to wheel the gas to their establishments. Where this provision is extended to the commercial and residential sectors, usually via brokers, the LDCs are not always absolved of their franchise charter responsibility to provide an effective supply backstop service to the so-called *core market*. Unless tariffs are modified to reflect these potential supply insurance costs, utilities are put at additional financial risk or remaining full service customers are forced to cross-subsidize the transport service users through higher tariffs. If backstop costs are reflected in LDC tariffs, large industrial customers are thereby encouraged to bypass the LDC and hook up directly to nearby transmission lines, creating redundant capacity on the LDC system. Clearly, traditional regulatory institutions and systems are subject to increasing pressures and may be called upon more often to serve as a disputes settlement mechanism.

Oil Pipelines

While usually subject to regulation, oil pipelines have often been set up on a joint venture basis by refiners and are typically common carriers. Price regulation has been rather passive since refiners are usually in a position to look after their own interests, and the regulatory focus has been on access, safety and environmental concerns. Interstate oil pipeline rate regulation in the US is undertaken by the Federal Energy Regulatory Commission (FERC), having inherited a form of cost-of-service type ratemaking methodology from the Interstate Commerce Commission (ICC) (Farrell and Forshay, 1994). In Canada, the National Energy Board (NEB) undertook formal regulation of interprovincial oil pipeline tolls in 1976, again on a cost-of-service basis. This move coincided with the extension of the Interprovincial Pipeline (IPL) to Montreal from Sarnia on the Ontario-Michigan border at the behest (and guarantee) of the federal government.

Recent moves in both jurisdictions portend well for a less onerous regulatory burden while providing encouragement to operating cost efficiencies. FERC Order 561 permits changes to rates based upon a price index without the need for supporting information. In 1994, the NEB issued guidelines whereby shippers were encouraged to negotiate toll methodologies with pipelines to preclude the need for formal hearings. Recently, IPL and Canadian oil producers negotiated a price index-based toll agreement which provides for a sharing of cost savings between shippers and pipeline shareholders (*The Regulatory Times*, 1995, pp. 1-2). Incentive rate regulation of this nature not only rewards operating efficiency gains but reduces the deadweight cost of regulation to the economy. It may also provide a cost-effective means to counteract the inherent tendency to dissipate potential monopoly economic rent in the form of higher costs to run the monopoly or to regulate it (Tollison and Wagner, 1991).

Joint ventures are also common among crude oil producers to benefit from the scale economies of single gathering pipelines or natural gas processing facilities. Even when not subject to price regulation, cotenants often agree to charge themselves fees based on utility cost-of-service principles (Gale, 1994). The regulator may still be called upon to serve as a dispute settlement mechanism, particularly in cases of excess demand for existing capacity. It is interesting to note that while oil pipelines fit virtually all of the classic natural monopoly characteristics, large fixed costs, increasing returns to scale, economies of scope for batch shipments (subadditivity), and the potential for destructive competition (Sharkey, 1982), the perceived requirement for regulation to serve the *public interest* is minimal by comparison to that for gas and electricity. This outcome is undoubtedly related to the difference in market power of the customers, potential competition from alternative means of transport and supply points, and downstream competition despite upstream cotenancies.

Market Boundaries

As described above, the areas over which energy natural monopolies have exercised influence have evolved, first expanding geographically, vertically and horizontally and more recently contracting as technology and market instruments have developed. In the electricity industry, geographical expansion and vertical integration was an extension of the economies of scale and scope associated with large generation stations and system load coordination. The coexistence of independent power generation was based upon industries such as aluminium smelters locating near hydro-electric sites, and industrial plants, which could utilize both the electricity and steam produced in thermal stations, such as chemical factories and district heating plants.

A number of factors have increased the potential role for independent power producers in recent years. The escalating capital costs of very large generating stations based on environmental assessment and mitigation costs, site planning and design costs, longer preproduction periods and slower demand growth, to name a few, have tended to offset the traditional scale economies. Site economies based on smaller size, cogeneration possibilities, "cookie cutter" design and equipment manufacturing economies as well as more pricing flexibility in negotiating fuel supplies favour smaller power stations that can be built on a shorter planning horizon to meet a slower rate of demand growth. Institutionally, the memories of "rate shock" as the significant nuclear station cost overruns were rolled into the historical rate base have left both consumers and politicians with a bias in favour of more manageable additions to the supply system, which would match slower demand growth, itself a function of the rate increases.

One of the fuel sources favoured for independent power production has been natural gas, in part for its environmental properties, but also in part because of new market instruments. While financiers still prefer longer-term financial instruments tied to fixed price fuel contracts, as in the early days of pipeline financing, market intermediaries such as brokers, aggregators and arbitragers have combined various instruments such as futures, options, hedging and formula pricing to share the input and output pricing risks over the life of the plant. Transmission pipelines and LDCs have been relegated to simple transporters of the input fuel and providers of backstop services such as storage to offset short-term supply/demand imbalances for these power producers.

Similarly, on the output side, electricity LDCs and transmission facilities can be used to wheel the power produced outside of the immediate market area. Institutional rigidities have slowed the development of a wholesale power market, reflecting the inherent possibility for opportunistic behaviour among the potential players, regulatory inertia and the existence of a continuing element of natural monopoly (transmission and distribution) even with complete deregulation. Further, many of the efficiencies associated with flexible markets have already been captured through pooling arrangements and short-term economy exchanges among potential participants. Given the technical control required to effect central dispatch and the limited role inventories, such as pump storage schemes, can play in levelling supply/demand imbalances, one might despair as to whether a transparent bulk power market might ever develop. Nevertheless, pricing policies and practices for wheeling power are evolving.

Prices equal to short-run costs encourage wheeling customers to make good short-run wheeling decisions that tend to equalize energy costs throughout the network, but such prices can distort customers' long-term decisions about such long-term commitments as constructing their own generating units, signing long-term firm power supply contracts, or constructing their own transmission lines. Prices equal to long-run costs encourage good long-run investment decisions of this sort, but can distort good decision-making about the optimum near-term use of network generation and transmission facilities for minimizing energy costs (Kelly, et al., 1987, pp. ix).

Over time and with familiarity, electronic bulletin boards and potentially electronic trading in power can be expected to play a more important role in developing a short-term market for electricity, much as the market for natural gas has already developed. Such instruments provide both current and potential market players with a benchmark for setting contract prices and for measuring their own performance. Transparency in pricing also serves to reduce the need for regulatory review of contract supply prices for LDCs. Already, a short-term market of a sort exists in the form of economy exchanges among utilities based upon short-run cost differentials within pooling arrangements with the economies shared by the participants.

It has been shown that where longer-term transmission contracts are in place, it would in theory be possible to calculate on an "ex-post" basis an implicit secondary market in capacity rights, based upon short-run cost differentials already in use for economy exchanges. With compensation to contract users of the transmission system for congestion caused by short-term fluctuations, efficient system economics and no impediment to the development of lowest cost incremental supply would be ensured (Hogan, 1990). The information and computational requirements to implement such a system are not insignificant, particularly when concepts such as reactive power (KVAR) as well as real power (kW) are explicitly treated in the pricing equation (Berg, 1983). Because of the inherent complexities of calculating node pricing where rewards to opportunistic behaviour are present, it may be necessary to maintain an audit role for regulators, at least during the transition phase to a truly open access system for electricity (Kahn and Baldrick, 1994).

Traditionally, natural gas and electricity utilities have not looked much beyond the customers' meters other than for safety inspections. The customers' time-of-use and load pattern fluctuations were all totalled into one monthly billing statement without regard for the supply costs incurred except in total. Third-party energy use consultants have advised on how a customer might rearrange consumption to reduce energy bills through improved equipment and/or use patterns, but rarely would time-of-use considerations enter into the calculations if the customer were not so billed.

With the advent of demand-side management (DSM) programmes, utilities can influence demand (increase, decrease or displace) so as to lower rates to customers through lower utility costs (Vollans, 1993). For example, consider a DSM programme which offers retail customers for water heating a rebate of some sort (a free water heater perhaps) in return for an agreement that their water heaters may be turned off by remote control by a central dispatcher for a short specified period, say two hours at a maximum. The dispatcher would then be in a position to regionally shed a portion of the load on very short notice rather than implement a costly peak load supply operation.

Such measures will induce moderate efficiency gains in end use but consumers and their energy-use consultants, however civic minded, will only respond *en masse* if they receive price signals which induce energy efficient behaviour.

> The efficiency gains are largely associated with appropriate rate structure reform. If more efficient retail pricing is our goal, deregulation of bulk power sales combined with continued retail rate regulation is not a particularly potent mechanism for achieving that goal in either the short run or the long run. If we want more efficient rate structures, state regulatory commissions and public enterprises must design and implement them (Joskow and Schmalensee, 1983, p. 166).

How might efficient retail rate structures be implemented, given the institutional and technical factors discussed above, and the fact that there will undoubtedly remain an element of natural monopoly that requires some sort of institutional control to prevent abuse of monopoly power? As we have discussed, oil, then gas and more recently electricity transmission can be (and have been) technically and economically separated or unbundled from the energy commodity transported and priced individually. The extension into gas distribution has already begun and could, at least conceptually, be undertaken in the area of electricity as well.

Aside from regulatory and institutional inertia, the major stumbling block to efficient retail rate structures has been the costs of metering. Over the past decade, the cost of computers and data storage has fallen dramatically. Moreover, at this very moment, more and more households are being wired into the so-called "information highway," providing a mechanism to provide virtually instantaneous feedback to consumers and utilities on household energy usage by individual appliance by time of day. It takes little imagination to envisage a world where consumers would accept programmes to shut off appliances or switch space heaters from one fuel source to another, at least in part, where the price signals were readily available. Initially, perhaps only commercial customers would avail themselves of such innovative programmes and some retail customers might never embark, but if the choice were available, a significant portion could be expected to join in over time on the basis of demonstrated savings.

Energy use consultants could be expected to develop the customer base and perhaps share the risk (and savings) with the customer as part of the service they provide. Those who for whatever reason decided not to participate would still have the regulated utility as the supplier of last resort on the traditional cost-of-service bundled rate structure. The true natural monopoly portion of the service, the transport of the commodity, would still be subject to regulation and could be expected to recover costs of providing back-up from those who did decide to participate. Rates for the transport service could remain on a regulated cost-of-service basis (probably complemented by incentive rate schemes to reward operating efficiencies), but prices for the energy commodity would be set by market forces.

The allocative inefficiencies of a regulated system would not be eliminated, but would be greatly reduced. Regulators would focus on safety and access questions rather than energy issues, creating room for some further consolidation of regulatory functions across industrial sectors in some areas. For example, energy regulatory agencies residual functions could be consolidated with other forms of transport and communication natural monopoly regulation to provide regulatory consistency across modes of transport.

Summary and Conclusions

It would appear that a certain level of natural monopoly regulation within the energy sector is inescapable, along with the associated loss of efficiency and the deadweight cost to society of providing the necessary policing. Nevertheless, markets evolve and technology changes, creating redundant regulation based on inertia and vested interests. As mature industries with a large infrastructure already in place, the tight regulation of facilities expansions could be largely eliminated, while subject to the same controls in place for facilities in any other sector of the economy. It is incumbent upon us to reevaluate the continuing need for the structures in place with a view to reducing the associated costs if possible even in the face of pressures from well-intentioned vested interest groups that would maintain the regulation in order to provide them with an instrument to effect their desired social change.

> Finally, the possibility of deregulating could regularly be entertained, since even though regulation may at one time have been necessary, that necessity may with the passage of time have waned. People change, as do circumstances and events; it is not obvious that, in the midst of change, the only permanence should be provided by regulations and regulatory bodies (Breton, 1976, p. 18).

Consumers and industries in jurisdictions which move to avail themselves of efficiency gains and lower associated costs will enjoy a competitive cost advantage over their neighbours that should lead to higher real incomes. Information processing technologies provide an opportunity to introduce efficient pricing schemes in traditional monopolies with all the associated benefits to consumers of open markets and lower costs. Progressive regulators will, to truly serve the *public interest,* encourage the necessary experiments and market trials to ensure an orderly transition to a more cost-effective and market responsive essential service.

References

Baumol, W.J. and D.F. Bradford (1970) 'Optimal Departures from Marginal Cost Pricing,' *American Economic Review* 40:3:265-83.

Berg, S.V. (1983) 'Power Factors and Efficient Pricing and Production of Reactive Power,' *The Energy Journal* 4: special electricity issue:93-102.

Breton, A. (1976) *The Regulation of Private Economic Activity* (Montreal: C.D. Howe Research Institute).

Farrell, J.H. and P.F. Forshay (1994) 'Competition Versus Regulation: Reform of Energy Regulation in North America,' *Energy and Natural Resources Law* 12:4:385-405.

Gale, I. (1994) 'Price Competition in Noncooperative Joint Ventures,' *International Journal of Industrial Organization* 12:1:53-69.

Hogan, W.W. (1989) *Approximating Efficient Short-run Prices for Electric Power Transmission* (Cambridge MA: Energy and Environmental Policy Centre, Harvard University), E-89-13.

—(1990) *Contract Networks for Electric Power Transmission.* (Cambridge MA: Energy and Environmental Policy Centre, Harvard University), E-90-17.

Joskow, P.L. and R. Schmalensee (1983) *Markets for Power* (Cambridge, MA: The MIT Press).

Kahn, A.E. (1981) Comment on 'Regulation in Theory and Practice: An Overview' by P.L. Joskow and R.C.Noll in G. Fromm (ed.) *Studies in Public Regulation* (Cambridge, MA: The MIT Press).

—(1988) *The Economics of Regulation: Principles and Institutions (vol. II: Institutional Issues)* (Cambridge, MA: The MIT Press).

Kahn, E. and R. Baldick (1994) 'Reactive Power is a Cheap Constraint,' *The Energy Journal* 15:4:191-201.

Kelly, K., J.S. Henderson and P. Nagler (1987) *Some Economic Principles For Pricing Wheeled Power* (Columbus, Ohio: The National Regulatory Research Institute), NRRI-87-7.

Pechman, C. (1993) *Regulating Power: The Economics of Electricity in the Information Age* (Boston: Kluwer Academic Publishers).

Priest, G.L. (1993) 'The Origins of Utility Regulation and "The Theories of Regulation" Debate,' *The Journal of Law & Economics* 35:1 (pt.2):289-323.

Regulatory Times (The) (1995) Calgary, February 22, 4:4:1-2.

Schmalensee, R. (1979) *The Control of Natural Monopolies* (Lexington, MA: D.C. Heath and Company).

Schumpeter, J.A. (1962) *The Theory of Economic Development* (translated from German by Redvers Opie) (Cambridge, MA: Harvard University Press).

Sharkey, W.W. (1982) *The Theory of Natural Monopoly* (Cambridge: Cambridge University Press).

Teece, D.J. (1990) 'Structure and Organization of the Natural Gas Industry: Differences between the United States and the Federal Republic of Germany and Implications for the Carrier Status of Pipelines,' *The Energy Journal* 11:3:1-35.

Tollinson, R.D. and R.E. Wagner (1991) 'The Logic of Natural Monopoly Regulation,' *Eastern Economic Journal* 17:4:483-90.

Vollans, G.E. (1993) 'Demand-Side Management: A Tool to Correct for Muted Pricing Signals to Consumers,' *Utilities Policy* 3:2: 113-17.

Appendix

Table 1: TFC Energy Market Shares (%)

	1960	1970	1980	1990	1992
USA					
Gas/Total	23.5	27.2	24.5	22.8	23.9
Elect/Total	7.2	9.6	13.2	16.5	17.0
Canada					
Gas/Total	9.8	17.1	20.8	25.3	26.1
Elect/Total	13.0	14.3	16.7	22.4	23.0
UK					
Gas/Total	5.1	9.0	27.2	28.4	29.0
Elect/Total	8.0	12.2	14.7	16.0	16.0
Japan					
Gas/Total	3.1	2.8	3.9	5.0	5.5
Elect/Total	13.8	13.5	17.8	22.0	22.0
Germany*					
Gas/Total	2.6	4.8	13.6	16.3	18.1
Elect/Total	8.0	9.7	12.9	15.6	16.0
France					
Gas/Total	3.9	5.8	13.4	17.0	17.8
Elect/Total	8.1	8.4	12.5	18.0	18.4
Italy					
Gas/Total	14.3	10.5	19.0	25.7	26.6
Elect/Total	11.4	10.2	12.9	15.4	15.7
North America					
Gas/Total	22.5	26.4	24.1	23.1	24.1
Elect/Total	7.6	10.0	13.6	17.1	17.6
Group of 4 (Europe)					
Gas/Total	5.0	6.9	17.4	20.9	22.0
Elect/Total	8.4	10.1	13.2	16.2	16.5
Group of 7					
Gas/Total	17.2	18.7	20.1	20.3	21.3
Elect/Total	8.1	10.3	13.9	17.5	17.9

*Data for the former German Democratic Republic have only been incorporated after 1969 in these series.

Table 2: TFC* Compound Annual Growth Rates (%)

	1970 /60	1980 /70	1990 /80	1992 /80	1992 /85	1992 /90	1992 /60
Group of 7							
TFC Gas	5.9	1.9	0.6	1.1	2.3	3.4	2.8
TFC Elect	7.5	4.2	2.8	2.7	2.9	2.1	4.6
TFC Total	5.0	1.2	0.5	0.6	1.3	1.0	2.2
GDP	4.9	3.2	2.8	2.6	2.7	1.4	3.5
Europe (4)							
TFC Gas	9.0	8.4	2.1	2.3	2.4	3.5	6.9
TFC Elect	7.8	3.3	2.2	2.1	2.3	1.7	4.4
TFC Total	5.9	1.0	0.2	0.3	0.7	0.7	2.3
GDP	4.5	2.6	2.3	2.1	2.6	1.2	3.1
North America							
TFC Gas	5.5	0.2	-0.1	0.5	2.2	3.2	2.0
TFC Elect	6.7	4.2	2.7	2.6	2.8	2.4	4.4
TFC Total	3.9	1.1	0.4	0.5	1.2	1.0	1.7
GDP	3.8	2.9	2.6	2.3	2.2	0.8	3.0
Japan							
TFC Gas	11.0	5.6	4.2	4.6	5.1	6.6	6.9
TFC Elect	11.9	4.9	3.9	3.6	4.1	2.0	6.6
TFC Total	12.2	2.1	1.8	1.9	2.9	2.2	5.2
GDP	10.0	4.4	4.0	3.8	3.9	2.6	5.9
USA							
TFC Gas	5.3	-0.2	-0.3	0.3	2.3	3.5	1.7
TFC Elect	6.7	4.1	2.6	2.6	2.9	2.5	4.4
TFC Total	3.8	0.8	0.4	0.5	1.3	1.1	1.6
GDP	3.7	2.7	2.6	2.3	2.2	0.9	2.9
Canada							
TFC Gas	10.9	16.3	2.2	2.1	1.3	1.5	5.9
TFC Elect	6.3	11.3	3.2	2.9	2.2	1.4	4.6
TFC Total	5.3	8.8	0.2	0.2	0.7	0.1	2.8
GDP	5.0	9.5	2.9	2.3	1.9	-0.5	3.8
Germany							
TFC Gas	14.1	11.8	1.4	2.1	1.7	3.3	8.8
TFC Elect	9.7	4.3	1.5	1.4	0.6	-0.5	4.8
TFC Total	7.8	1.4	-0.4	-0.7	-0.9	-1.8	2.6
GDP	4.3	2.7	2.2	2.8	3.2	3.0	3.1
UK							
TFC Gas	7.7	10.6	1.2	1.4	1.0	2.5	6.2
TFC Elect	6.2	1.3	1.6	1.6	2.2	1.6	3.0
TFC Total	2.0	-0.5	0.7	0.9	1.3	1.5	0.8
GDP	2.8	1.9	2.6	2.0	1.9	-1.4	2.2
France							
TFC Gas	10.4	10.1	2.4	2.9	2.3	5.6	7.5
TFC Elect	6.8	5.6	3.7	3.8	4.0	4.4	5.3
TFC Total	6.4	1.6	0.0	0.6	1.7	3.4	2.7
GDP	5.4	3.2	2.3	2.1	2.5	1.0	3.5
Italy							
TFC Gas	5.9	7.9	4.1	4.0	5.8	3.3	5.8
TFC Elect	7.9	4.4	2.9	2.8	3.6	2.1	4.9
TFC Total	9.0	2.0	1.2	1.2	2.2	1.5	3.9
GDP	5.6	3.7	2.2	2.0	2.4	1.0	3.6

* TFC (Total Final Consumption) from *Energy Balances of OECD Countries*, an IEA/OECD publication.

Russian Oil Prices: Courting the World Market

Professor Khartukov is Head, World Energy Analysis & Forecasting Group (GAPMER), Ministry of Foreign Affairs of the Russian Federation; and General Director, International Center for Petroleum Business Studies, Moscow, Russia.

EUGENE M. KHARTUKOV

While unprecedented cost-push inflation and stifling oil taxation have made Russia's ex-pump prices comparable to those in some Western countries, the backwardness of the country's refining industry is keeping domestic prices of crude oil substantially below world market parities. This paper argues that, even though the rapid "globalization" of internal crude oil prices is on the Russian government's agenda, their immediate rise to world levels would be neither desirable nor actually possible.

Export Prices: Almost Free

Even though world oil markets are competitive and deemed to operate so as to align the prices of different countries' inputs, this is not yet wholly the case with Russian crude and oil product exports, a part of which is still fettered by inter-governmental agreements and price controls. First of all, it relates to Russia's trade with the "near abroad"—a group of neighboring countries, which includes all the former Soviet republics, with the exception of the Baltic states. Although acting in opposite directions, those regulations tend to lower substantially the average unit value of Russia's oil (and particularly crude oil) exports to its neighbors vis-à-vis export prices for the "far abroad." For instance, according to the State Statistics Committee of the Russian Federation (Goskomstat), in the first half of 1995, the average border price of crude oil destined for the "near abroad" was US$75.04/tonne (t) as against US$114.77/t for crude exported to the "far-abroad," hard-currency markets. In turn, weighted average prices for oil products shipped to these two groups of countries amounted to US$92.41/t and US$101.34/t, respectively.[1]

After the breakup of the Soviet Union, the regularly concluded bilateral agreements, which provided for supplies of Russian crude and products (usually in exchange for other goods and services), became a typical feature of Russia's trade with Ukraine, Belarus, and Moldova. As a rule, Russian oil supplies under inter-governmental deals enjoy customs duty exemptions and are often priced at 15% to 20% below comparative world prices.[2] Such deliveries account for about 80% of Russia's "near-abroad" exports of crude oil and 30-40% of oil product supplies.

The remaining deliveries to the "near abroad" are provided on "free" commercial terms. Still, these "deregulated," commercial exports are not completely free of price controls: since June 1993, the Russian government has prohibited any commercial export of crude or product sold below "average world prices," which are arbitrarily determined by the official price watchdog (the Russian Federation's Committee on Price Policy and, since 1995, Ministry of Economy) in cooperation and agreement with related trade and industry departments (Ministry of Foreign Economic Relations, and Ministry of Fuel and Energy). These notional "world prices" are regularly (as a rule, quarterly) revised "to reflect world market fluctuations" and, with a few recent exceptions, serve as a floor to border (f.o.b.) prices, inclusive of applicable Russian taxes and duties.[3] Authorities argue that these calculated floor prices are average world prices for the preceding three months, which are then translated into roubles or acceptable local currencies at exchange rates set by the Central Bank of Russia on the 15th of the month preceding the delivery. Although serving the noble goal of preventing dumping of Russian crude and products in "near abroad" markets, these arbitrarily determined world price parities basically reflect the premium price that has to be paid by ex-Soviet republics for their lack of instant alternative supplies. In turn, the forced overpricing of "near-abroad" exports evidently undermines their competitiveness and makes Russian exporters seek other, truly deregulated markets.

Unfortunately, the sought-for free (and hard-currency) markets of the "far abroad" (which are rarely found beyond nearby Central and Western Europe) cannot easily digest the released excess of Russian crude and products, and are exceptionally sensitive to their unstable supplies. This can be illustrated by the relative price dynamics of Russia's main export stream—Urals Blend—and Dated Brent, which is typically used as a price marker for Russian crude exports (see Figure 1). In addition to the obvious two-year trend of narrowing price differentials between the two crude streams (which reflects gradually reduced supplies of sour, heavy oils from the Middle East), the spot price of Urals also reacted to seasonal and occasional swings in Russian oil exports destined for Europe. In particular, during the typical summer oversupply of Urals, aggravated by temporarily duty-free exports of Russian fuel oil (May-September 1994), the differential peaked in July—at US$0.85/barrel (bbl), according to *Bloomberg LP*. In turn, during the winter the gap between the prices virtually disappeared, owing to weather and red-tape disruptions in

1/ See *Business MN* (19 July 1995, p.18).

2/ Though initially based on related world prices, such deals normally later adopt markdowns and reciprocal concessions. For instance, Ukraine—the largest importer of Russian oil—used to acquire oil products with substantial (though gradually decreasing) discounts off world prices and, according to a recent trade protocol with Moscow, buys heavy and sour crude from Tatarstan with a 20% markdown.

3/ Following the establishment of a customs union between Russia, Belarus, and Kazakhstan at the beginning of 1995, the allies have enjoyed duty-free trade of goods, including crude oil and oil products. Thus, in case of Kazakhstan, Russian exporters are allowed to lower the "prescribed" minimum prices by deducting current export duties, while supplies to Belarus may be effected (since mid-May) at prices that are not lower than those in Russia's domestic market. As a result, in June 1995, Russian crude oil could be sold to Kazakhstan at a relatively low US$99/t and was actually exported to Belarus at a mere US$75/t. At the same time, Russia's oil products were imported by its closest trade partners at 50-60% of calculated quasi-world prices.

dollars
per barrel

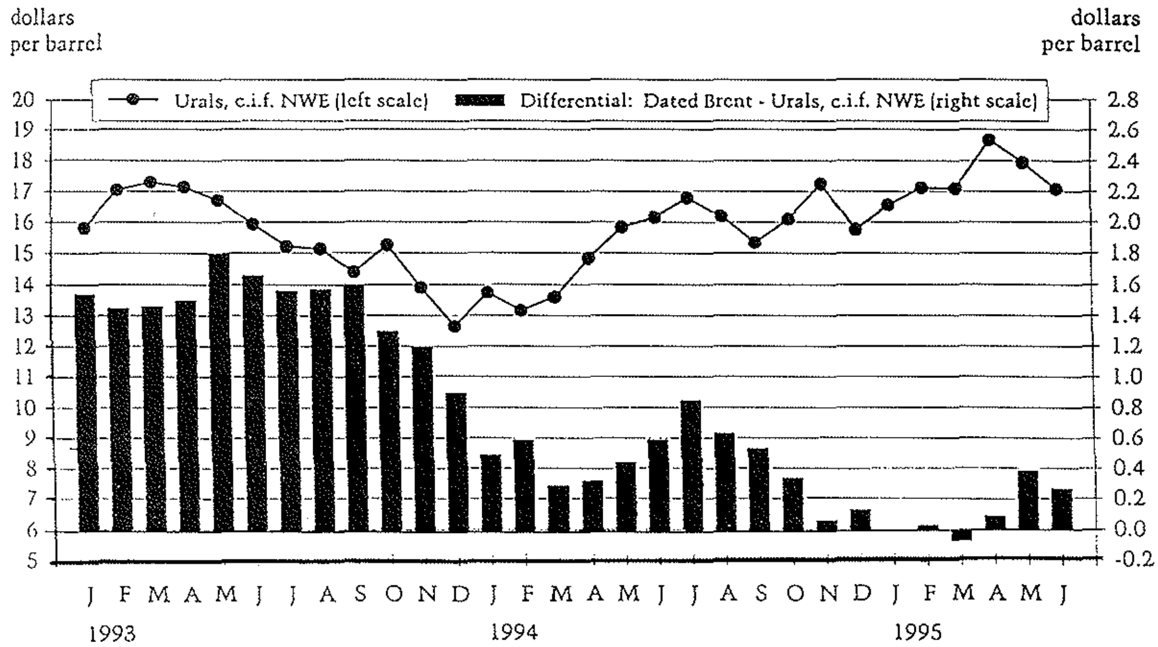

Figure 1: Monthly Average Export Prices of Russian Crude Oil, January 1993 – June 1995

crude oil shipments from the Black Sea and a temporary ban on *mazut* exports, in effect from December 1994 through March 1995, which adversely affected the availability of Russian straight-run fuel oil (E-4). Finally, another contraction in Russian crude supplies, caused by the slow implementation of new export rules and repairs to a pipeline that feeds Russia's main oil seaport of Novorossiysk, sent the Urals spot price 8¢/bbl above Dated Brent in March 1995.

While engaging in direct competition with other supplies of sour refinery feedstock, the often excessive and irregular exports of Russian crude and E-4 fuel tend, in turn, to destabilize West European markets and undermine prices. Besides, in contrast with the forcedly overpriced commercial deliveries to the usually insolvent "near abroad," Russian oil exporters try to make up by bidding for lower, but instant, hard-currency payments. Consequently, 1994 export prices for Russia's crude and products destined for the "far abroad" were typically 5% to 15% lower than comparable world prices.[4] Still, this looks like a substantial improvement compared to 1993 when up to 20% of fuel oil, 70% of diesel fuel, 80% of light products, and 94% of crude oil were exported from Russia at even heavier discounts.[5]

This progressive improvement in the pricing of oil exports, however, had little to do

4/ According to a special report prepared by Russia's leading market research centers (TsEK and VNIKI), in the first three quarters of 1994, the country's average export prices were below comparable world levels by 4.1% in the case of diesel fuel, by 6% for crude oil, and by 14.7% for fuel oil, while only negligible exports of straight-run gasoline (naphtha) in September 1994 were, on the average, priced 11% above the world level (see *Kommersant-Daily*, 22 February 1995, p.5).

5/ See *Business MN* (20 April 1994, p.17). According to a parliamentary report on the foreign economic activity of the Russian oil industry in 1993, over 35 million tonnes of crude oil were exported at dumping prices ranging between US$17.4/t and US$46.8/t (see *Rossiyskiy Neftyanoy Byulleten*, 15 December 1994, Nos. 47/48, p.19).

Table 1: Russia's Export Duties for Liquid Fuels, 1992-95 (ECUs/tonne)

Product	Base Rate of Duty, Effective as of: 1992 Jan.	1992 June	1992 Dec.	1993 June	1993 Dec.	1994 June	1994 Dec.	1995 June
Crude Oil (1)	26.0	20.8	38.0	30.0	30.0	30.0	30.0	20.0
Motor Gasoline	57.0	45.6	55.0	40.0	40.0	40.0	40.0	12.0
Other Gasolines	57.0	45.6	55.0	40.0	40.0	40.0	40.0	20.0
Jet Fuel	65.0	52.0	55.0	40.0	40.0	40.0	40.0	20.0
Other Kerosenes	65.0	52.0	52.0	40.0	40.0	40.0	40.0	15.0
Gasoil/Diesel Fuel	51.0	40.8	52.0	30.0	30.0	30.0	30.0	12.0
Fuel Oil (*mazut*)	24.0	19.2	25.0	15.0	8.0	0(2)	(3)	4.0
Lube Oils	85.0	68.0	55.0	23.0	23.0	23.0	23.0	2.0
Liquefied Gases	24.0	15.2	31.0	18.0	18.0	18.0	5.0	2.0

(1) Including gas condensate. (2) Exports were duty-free from May until October 1994. (3) Exports were banned from December 1994 until April 1995.

with the growing experience of new Russian traders. As domestic product prices, swelled by higher taxes, approached world levels, the objective possibilities of further underpricing (and dumping) simply shrank. Moreover, in some cases, owing to heavy export duties and relatively higher transportation costs, the idea of exporting crude oil and, especially, oil products lost some of its economic appeal.

As for *export duties*, these were first introduced at the beginning of 1992, following the dismantlement of the state foreign-trade monopoly, and since then have been fixed in European currency units (ECUs), but payable in roubles in line with the current exchange rate set by the Central Bank of Russia. Although these customs duties have tended to decrease and, under pressure from the World Bank and IMF, must be completely phased out in the "near future," they still account for around 25% of the average f.o.b. price for crude oil and 10-12% for gasoil exported to Western Europe (see Table 1).

In addition to the above duties, Russian exports of crude and products to the "far abroad" are heavily "taxed" by *extra transportation costs*, which include supplementary hard-currency payments to Transneft (the state-owned oil-transportation monopoly), transit tariffs through the territories of Russia's western neighbors and, in the case of seaborne shipments, various and rather hefty port dues. Taken together, these transport-related charges, which are not payable for domestic and "near-abroad" sales, make export shipping of crude and products much more expensive. Coupled with sizeable export duties, the higher transportation costs palpably eat into an exporter's revenues and compel many export-oriented projects to lobby and wait for export duty exemptions.

High vulnerability to additional export charges is most typical of oil-producing joint ventures with foreign partners, which have unrestricted export rights for their output and are usually (though far from automatically!) exempted from export duties until payback of their project investments. Table 2, which incorporates the results of two recent feasibility studies by Western economists, shows apparent differences in the price composition of Russian crude being sold domestically or exported.

Although some of the assumptions made by the Western analysts are rather questionable, the resultant figures highlight the fact that, in the case of the non-CIS ("far-abroad") exports, the additional export-related charges tend to be counterbalanced by higher gross revenues that leave room for larger profits. In turn, the CIS ("near-abroad") exports are arguably presented as the least attractive destination of crude oil sales, owing to the unavoidable value-added tax as well as to lower export prices (which, however, do not apply to commercial sales). Moreover, exports to Belarus and Kazakhstan, both of which participate in a trilateral customs union with the Russian Federation, are free of related duties. As a result, deliveries of crude and products to

Table 2: Typical Breakdown of Export and Domestic Prices for Russian Oil, in US$/bbl

Price Component	Occidental Petroleum, February 1995 (1)			CS First Boston March 1995 (2)	
	Non-CIS Export	CIS Export	Domestic Sales	Non-CIS Export	Domestic Sales
Selling Price	15.00	10.12	7.00	16.00	7.00
Export Duty	3.82	3.82	–	3.94	–
Value-Added Tax	–	2.02	1.31	–	1.17
Special Tax	n/a	n/a	n/a	0.48	0.21
MRR Contributions (3)	0.83	0.36	0.36	1.60	0.58
Royalty	0.54	0.24	0.20	0.71	0.34
Excise Duty	0.96	0.96	0.96	1.14	1.14
Other Non-Profit Taxes (4)	0.55	0.37	0.25	0.06	0.02
Transportation Charges	1.90	1.72	0.20	2.00	0.40
Export Commission Fee (5)	0.09	0.06	–	n/a	n/a
Production Costs (6)	3.20	3.20	3.20	4.00	4.00
Pre-Tax Profit (Loss)	3.11	(2.63)	0.52	2.07	(0.86)
Profit Tax	0.93	–	0.16	0.79	–
After-Tax Profit (Loss)	2.18	(2.63)	0.36	1.28	(0.86)

(1) As applied to Occidental's joint venture Vanyeganneft (source: *Russian Petroleum Investor*, April 1995, p.32). (2) As applied to a hypothetical project - adapted from Amor (1995, pp.43-44). (3) Contributions for mineral reserves replacement. (4) Mainly road-use and local taxes. (5) To an authorized ("special") exporter. (6) Operating expenses and depreciation.

these nearby markets are more lucrative than exports to the remote "far abroad"—provided that timely payments are received! At the same time, non-CIS exports, which generally guarantee instant hard-currency payment, have their own commercial disadvantages. In some instances, the extra transportation costs outweigh apparent benefits of higher export prices and prompt Russian oil producers to consider redirecting their marketing efforts to the "near abroad."[6]

Even so, the steadily shrinking oil deliveries to the CIS and persistently increasing crude and product sales outside the countries of the former Soviet Union (FSU) evidently imply that these hard-currency exports are more commercially attractive. According to a recent profitability analysis of non-FSU oil exports (Tankaev 1995), in the first quarter of 1995 a cargo of Russian crude destined for southern Europe (port of Augusta) fetched a typical c.i.f. price of US$120/t, or US$16.55/bbl, which normally broke down as follows (in %): oil production costs and downstream taxes – 35.0; domestic transportation costs (to the Russian-Ukrainian border) – 11.5; transit fees (via Ukraine) – 2.0; port and customs-clearance dues – 3.1; sea transportation costs (freight and insurance) – 11.6; "special" exporter's and bank commissions – 1.0; export-related fiscal charges (export duty and VAT+ST on purchased services) – 26.5; and, finally, net profit – 9.3, which corresponds to US$11.1/t or US$1.53 /bbl. Not too bad by Western standards, but still just a trace of what producers could have reinvested without paying that hated US$4 /bbl export duty!

Domestic vs. World Prices

It is often argued that the existing export duties keep domestic crude oil prices from rushing toward comparative world market levels. Beginning in 1991, official representatives of the World Bank, the International Monetary Fund, and the International Energy Agency (IEA) have repeatedly insisted or advised that domestic oil prices in Russia should be freed and raised to world parities. Thus, a special study on Russian energy prices completed by IEA experts in 1994, explicitly suggested that "domestic crude oil and product prices should

6/ See, for example, *Russian Petroleum Investor* (April 1995, pp.32-34); *Petroleum Intelligence Weekly* (22 May 1995, pp.3-4).

reach world market levels as soon as possible through abolition of export restrictions." (IEA 1994, p.82) Later, it became a popular *cliché* to state that (despite the existing export duties) current domestic prices for some oil products (particularly gasoline) have reached and surpassed those levels and that crude oil prices should follow suit. Neither of these truisms, however, was ever subjected to careful examination.

Before examining relationships between Russian domestic and world oil prices, it would be expedient to define and clarify the subject of analysis. First, it should be clear that, in a competitive (virtually deregulated) marketplace, domestic prices must generally differ from export (import) ones by an amount reflective of the customs duties applied. However, this is not the only factor that determines internal market prices. Being driven by the interplay of localized, indigenous supply and demand, domestic prices reveal a certain autonomy and "naturally" differ from "outside" prices, unless and until the underlying imbalance between local and foreign markets is leveled off in the longer term.

Second, market prices of crude oil, which is almost exclusively used as refinery feedstock, are objectively capped by ex-refinery prices (and processing costs) and, consequently, cannot exceed the compatible *net product worth* of the consuming refineries' output for any long period of time.

Finally, only compatible prices can be meaningfully compared. This precludes relating domestic prices, which include specific indirect taxes, to world prices that represent export (or import) prices of major exporters (importers) and are free of such internal fiscal charges. Also, this prevents direct cross-evaluation of different crudes and dissimilar product grades. Consequently, only tax-free producer prices for crude oil and ex-refinery prices for oil products can be meaningfully compared with f.o.b. (c.i.f.) prices for similar crudes and products at the closest centers of international oil trade (say, at Rotterdam, ARA, or Northwest Europe).

Among available international comparisons of Russian oil prices, only the data regularly published by the Russian Federation's Ministry of Fuel and Energy (Mintopenergo) can loosely meet the above criteria. Unlike other, better publicized analyses, the ministry's reports deal with wholesale enterprise (*i.e.*, producer and ex-refinery) prices, which are compared to Dated Brent and European bulk prices of similar oil products c.i.f. Northwest Europe. Not surprisingly, the results thus obtained do not support the axiom that the Russian product prices have reached and even exceeded corresponding world levels (see Table 3).

Take, for example, crude oil. According to Mintopenergo, its average producer price increased from 0.3% of the Dated Brent price at the end of 1991 to 20% in December 1992, 46% at the end of 1993, and nearly 50% in June 1995. This may lead to the tempting conclusion that Russia's gradually liberated market has clearly been setting domestic oil prices right on way to world parities. Nothing, however, may prove to be more misleading than this illusory trend. First, there is quite a poor correlation between the evolution of export duties for Russian oil (see Table 1) and its relative price dynamics vis-à-vis the European marker crude.

Second, the price comparison with light and sweet Brent crude is not sufficiently correct, and the relative appreciation of Russia's heavier and sourer oil, observed during the last year and a half, must rather reflect the ever narrowing price differential between Urals Blend and Dated Brent, caused by the shrinking supplies of competing refinery feedstock. Third, in the first half of 1995, Russia's oil producer prices were substantially boosted by the increased excise duty, which was raised from an average of Rbl 21,600/t (US$5.1/t) in the first quarter of 1995 to an average of Rbl 41,400/t (US$8.8/t) in June.

Fourth, the persistent overproduction of Russian oil suggests that potential increases in domestic prices are hindered, not so much by the remaining export duties, but rather by the insufficient inland demand for refinery feedstock. In other words, domestic crude oil prices have bumped into the relatively low ceiling of Russian refinery prices which, in

Table 3: World and Russian Domestic Prices of Crude Oil and Oil Products, 1991-95 (1)

	Dec. 1991	Dec. 1992	Dec. 1993	June 1994	Dec. 1994	Mar. 1995	June 1995
Crude Oil							
World price, US$/t (2)	138.4	119.0	89.3	108.0	112.0	118.3	113.0
Domestic price, US$/t (3)	0.4	23.9	41.3	39.3	29.4	42.8	55.7
Domestic in % of world price	*0.3*	*20.1*	*46.2*	*36.4*	*26.3*	*36.2*	*49.3*
Motor Gasoline							
World price, US$/t (2)	190.3	208.5	142.1	160.0	170.0	173.0	180.0
Domestic price, US$/t (3)	0.7	44.8	80.5	76.9	70.6	100.8	133.0
Domestic in % of world price	*0.4*	*21.4*	*56.6*	*48.1*	*41.5*	*58.3*	*73.9*
Diesel Fuel							
World price, US$/t (2)	176.6	195.7	140.7	149.0	143.0	149.0	157.0
Domestic price, US$/t (3)	0.7	37.9	75.6	73.6	64.9	90.2	114.0
Domestic in % of world price	*0.4*	*19.3*	*53.7*	*49.4*	*45.4*	*60.5*	*72.6*
Heavy Fuel Oil							
World price, US$/t (2)	106.0	72.7	63.0	86.0	99.0	106.0	92.0
Domestic price, US$/t (3)	0.4	19.7	25.1	27.5	30.6	44.6	48.3
Domestic in % of world price	*0.4*	*27.1*	*39.8*	*32.0*	*30.9*	*42.1*	*52.5*

(1) Based on Mintopenergo data. (2) At Northwest Europe. (3) At Russian market exchange rates.

turn, have found themselves suppressed by the heavy product taxation, high distribution costs and, finally, exorbitant end-user prices.

The problem is greatly aggravated by the backwardness of most Russian refineries, which are normally short of upgrading capacities. As a result, the country's refinery yield is dominated by heavy fuel oil (35-40%), while more valuable lighter products (gasoline, naphtha, LPG, kerosene and gasoil) account, on average, for about one-half of refinery output. Technically speaking, the depth of crude processing (*i.e.*, the ratio of produced light and medium distillates to total refinery throughput) in Russia is typically quite low: 55-63%, compared to 75-85% in Western Europe and Japan, and 85-95% in the United States (see Figure 2).

Hence, gross product worth (GPW), or the weighted average market price of products, yielded by outmoded Russian refineries is also rather low. The poor market value of refinery output encapsulates the following surviving dilemma: to raise product prices (which was successfully done until the end of 1993, when final users became virtually unable to pay) or, alternatively, to curtail the intake of expensive refinery feedstock and, by doing so, exert downward pressure on crude oil prices. The latter can just be observed since the end of 1993, when the relative price of Russian crude peaked at 46% of the European benchmark price, and national oil producers experienced an unprecedented crisis of overproduction.

Let's look at the GPW of Russian refinery output at that dramatic time and compare it with concurrent crude oil prices (see Table 4). When estimated on the basis of ex-refinery prices prevailing in December 1993 (Rbl 63,800/t), the typical GPW hardly covered the average crude acquisition cost (Rbl 52,400/t), forcing refiners to offset loss-making sales of fuel oil by marginally profitable production of higher-priced gasoline. At the same time, calculated at European bulk prices of the ARA range, it gave an encouraging US$100/t (or almost Rbl 125,000/t) which, however, should have been netbacked to under Rbl 50,000/t by deducting related shipping costs and export duties. Even the artificially overpriced commercial exports to the "near abroad" did not provide too much relief, with netbacked prices of products destined for ex-Soviet republics offering only around Rbl 62,000/t to cover both refinery acquisition and processing costs.

Thus, Russian crude oil is considerably un

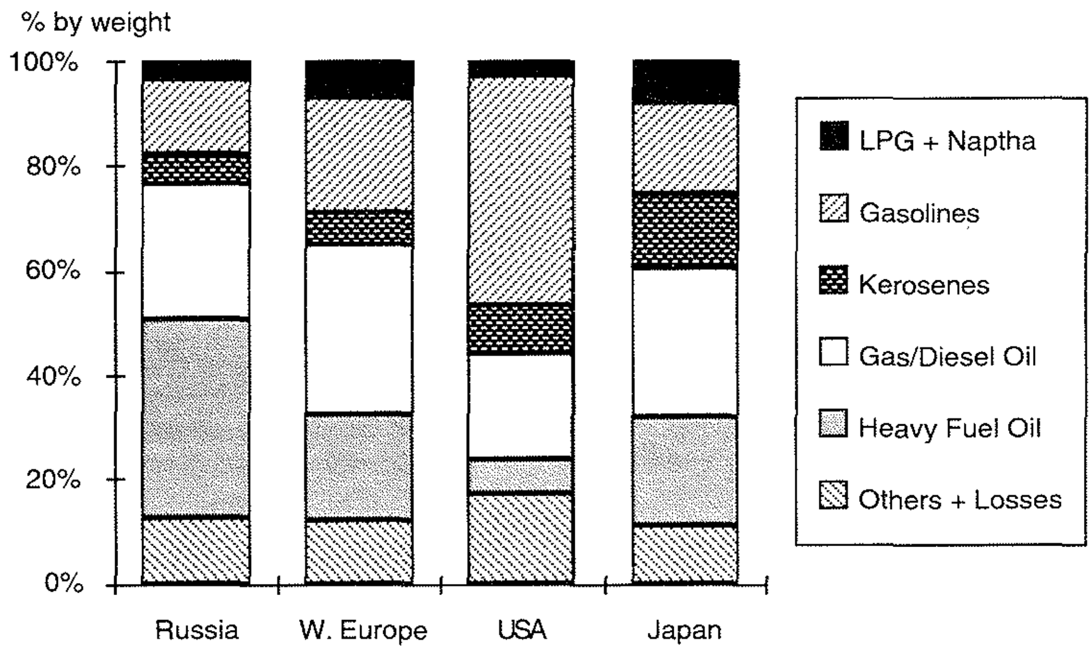

Figure 2: Average refinery yield in Russia and developed market economies, 1993

Table 4: Average Gross Product Worth of Russian Refineries, December 1993

	Refinery Yield(%)	Product Prices (1) '000 Rbl/t		
		A	B(2)	C(2)
Liquefied Petroleum Gas	1.8	60.0	161.2	183
Naphtha	2.0	70.0	202.2	162
Low-Grade Mogas (3)	13.2	97.0	210.9	136
High-Grade Mogas (4)	1.0	111.1	233.2	165
Jet Kerosene	5.3	102.5	212.1	209
Diesel Fuel	25.3	93.8	207.1	186
Furnace Fuel Oil	37.0	32.3	85.0	76
Others (5)	9.4	(5)	(5)	(5)
Gross Product Worth:		*63.8*	*146.7*	*124.7*

(1) Actual or estimated, average December prices: A - ex-refinery (excluding value-added tax and sales tax on motor fuels and lubes); B - floor prices for exports to the CIS (including Value-added tax, sales tax on motor fuels and lubes, and export duties); C - estimated bulk prices f.o.b./c.i.f. Northwest Europe (2) Converted from US dollars at December 1993 average exchange rate of 1,240.3 Rbl/$. (3) Regular leaded and unleaded motor gasolines (A-76). (4) Premium leaded and unleaded motor gasolines (A-92, AI-93 and higher grades). (5) Including lube oils, oil bitumen, marine fuel oil, aromatics, light oven fuel, petroleum coke, paraffins, lighting kerosene, aviation gasoline, solvents and refinery gas.

derpriced primarily because of the poor state of the national refining industry, which requires radical modernization—not to mention the long-awaited replacement of its dilapidated facilities, over 80% of which are physically worn out. However, the nationwide refinery modernization (or, over a shorter time horizon, reconstruction) program, which was declared by the Russian government in 1992 and envisages the deepening of oil processing to 82-85%, needs 12-14 years to implement and will hardly ensure more than an average deepening of the processing rate to 64% by the end of 1997 (*Neft Rossii* 1995, No. 5, p.23). In the meantime, the government will likely try (in vain) to "free" domestic prices of crude oil through the intended chopping of its export duty or, otherwise, may allow for limited price growth by the promised reduction of oil product taxes.

Should the current oil taxation be left basically intact, however, an instantaneous relative rise in domestic crude oil prices over and above the calamitous 50% of the known world oil price may have a disastrous effect on the national refining (and, subsequently, oil-producing) industry.[7] In particular, the envisaged phasing out of export duties on crude oil may leave the country's refineries short of affordable crude feedstock, which will tend to flow to the more lucrative foreign markets, with the resultant "natural" increase in domestic prices. The consequent protectionism of the national refining industry through prohibitive import tariffs on foreign products would be the next logical step of such a myopic policy.

In turn, under the pressure of enormous budget deficits, the declared intention to reduce oil product taxes seems unlikely to materialize without increasing fiscal pressures on other, better-off sectors of the national economy (presumably, on the gas industry and even on the reanimated oil production itself). Still, even if oil producers are not directly affected by such a redistribution of the tax burden, they will hardly get any ease from the heavy fiscal charges that currently snip off a hefty two-thirds of their overall sales proceeds, and thus greatly limit upstream investment possibilities. Bearing in mind the best examples of foreign oil taxation,[8] it would be expedient to consider just the opposite shift of tax burden—from the upstream to the downstream sector—which, however, has nothing to do with the targeted "globalization" of domestic crude oil prices. Rather, owing to the end-user's likely resistance to ever higher oil costs, both crude producer prices and ex-refinery product prices in Russia will most likely initially recede from achieved world market heights.

Toward Optimal Price Proportions

Though undoubtedly important, oil pricing is just one element of Russia's new energy policy, which should not neglect prices for other energy sources. Unlike the former system of centralized administrative pricing, which actually allowed any subjectively set inter-fuel price relations, the emerging energy market is increasingly sensitive to fuel price distortions and disproportions. For instance, domestic prices for natural gas are still firmly kept by Gazprom, the Russian gas monopoly (and monopsony), below the full production and transmission costs, and are heftily subsidized by modestly taxed gas-export revenues. This puts strong competitive pressure on deregulated (and no longer subsidized) prices of furnace fuel oil and steam coal (see Table 5). While refiners, who can offset *mazut*-related losses by profits made on other products and hard-currency sales of E-4 fuel to Europe, are still able to withstand the pressure, coal producers, who are locked out of export markets by exorbitant railroad tariffs, are steadily being dislocated from the domestic power-generation market too.

Understandably, inter-fuel pricing has become a major issue of Russia's long-term energy strategy, which is still being worked out following the government's 1993 request. According to main theses of this strategy, which were approved by a special interdepartmental commission in December 1994, Russia's energy policy for the period up to 2010 envisages a step-by-step increase of domestic fuel prices

7/ In July 1995, the Central Bank of the Russian Federation began to control the rouble/dollar exchange rate within the bounds of the so-called "hard-currency corridor" in order to hinder market-driven depreciation of the rouble. As a result, direct comparisons of world oil prices with the artificially inflated dollar-denominated domestic prices have become impossible. However, further comparative analysis can be conducted with account of the real purchasing power of US dollars spent in Russia. In particular, by the end of 1995, the average domestic price of oil had reached Rbl 282,000/t or, based on the controlled exchange rate, US$61/t – which would have formally meant around 62% of Dated Brent's December price. However, at the same time (since June 1995), Russia's persistent inflation has lowered the purchasing power of the domestically hobbled US dollar by a hefty 24.5% (based on Goskomstat data published in *Delovoy Mir*, 17 and 24 January 1996).

8/ According to IEA (1994, pp.46-49), in the United Kingdom and Norway, upstream oil taxes (royalties and corporate income taxes) took only 28% of wellhead revenues, while downstream taxation accounted, respectively, for 62% and 58% of weighted average end-user ex-VAT prices of products manufactured from North Sea oil in 1993. In turn, the fiscal components in Russia's comparable prices of crude and products were, on average, 60% and 13%, respectively.

Table 5: Average Wholesale Industry Prices of Main Fuels in Russia (in Absolute and Relative Terms), 1991-94 (1)

	Dec. 1991	Dec. 1992	Dec. 1993	June 1994	Dec. 1994	June 1995
Crude Oil						
Rbl/t	70.0	13,440	59,040	92,250	123,250	314,700
Rbl/t.o.e.(2)	69.3	13,310	58,460	91,340	122,030	311,600
Motor Gasoline (3)						
Rbl/t	205.0	31,620	181,450	322.700	560,150	1,586,900
Rbl/t.o.e.	191.6	29,550	169,580	301.590	523,500	1,483,070
relative (4)	*2.76*	*2.22*	*2.90*	*3.30*	*4.29*	*4.76*
Diesel Fuel						
Rbl/t	143.0	26,250	162,220	275,200	464,130	1,090,500
Rbl/t.o.e.	141.6	25,990	160,615	272,480	459,540	1,079,700
relative (4)	*2.04*	*1.95*	*2.75*	*2.98*	*3.77*	*3.47*
Furnace Fuel Oil						
Rbl/t	78.0	12,120	47,500	92,560	192,640	409,050
Rbl/t.o.e.	81.3	12,630	49,480	96,410	200.660	426,080
relative (4)	*1.17*	*0.95*	*0.85*	*1.06*	*1.64*	*1.37*
Natural Gas						
Rbl/1,000 cubic meters	52.0	1,730	21,835	46,950	73,770	207,820
Rbl/t.o.e.	65.0	2,160	27,295	58,690	92,220	259,800
relative (4)	*0.94*	*0.16*	*0.47*	*0.64*	*0.76*	*0.83*
Steam Coal						
Rbl/t	24.7	1,240	11,720	22,960	36,640	74,910
Rbl/t.o.e.	53.7	2,700	25,480	49,920	79,660	162,840
relative (4)	*0.77*	*0.20*	*0.44*	*0.55*	*0.65*	*0.52*

(1) Based on data from the Russian Federation's Ministry of Fuel and Energy. Including all applicable taxes (*e.g.*, value-added tax, special tax, sales tax on motor fuels and lubes, and excise duty); excluding delivery (transportation or distribution) charges. (2) Tonne of oil equivalent (1 t.o.e. = 10^{10} calories = 39.683 MMBtu). (3) Regular (A-76) grade. (4) In relation to crude oil price per t.o.e. (on the basis of net energy content).

above energy replacement costs, and toward world prices of oil and gas. Furthermore, it is argued that energy pricing should henceforth be aimed mainly at "gradually bringing the domestic price structure in line with world price proportions."[9]

Despite its encouraging and seemingly constructive tone, the approved strategic directive means, in fact, that another misleading phantasm is becoming a key guideline of Russia's energy pricing, which is now steered toward another freakish and wayward goal. Indeed, optimal price relationships between different energy sources are objectively determined by inter-fuel competition, which tends to align market prices of their common utility units in every given sector of final energy consumption. Consequently, deregulated domestic prices of each primary energy source (and, thus, of price relations with other fuels) reflect existing proportions of final use in various sectors of a national economy, on the one hand, and of sectoral (competitively leveled) end-user prices, on the other hand. In turn, world energy prices are vastly distanced from those inland hubs of direct inter-fuel competition by transnational transportation and intranational distribution and taxation. As such, they rather mirror overall patterns of multinational fuel trade. Hence, the intended copying of global price proportions would be as good for specific domestic pricing as using heavy, long-range artillery for shooting delicate quails.

Instead of targeting that phantasmal price "globalization," the priorities of Russia's energy price policy would be better redirected toward serving the optimal and most efficient use of the country's available energy potential. For the nation with the world's largest resources of natural gas covering over two-fifths of its total energy requirements, this should be

9/ See Interdepartmental Commission on Program Development (1994).

primarily addressed to the imminent rationalization of domestic gas prices, which currently distort the whole national price structure.

References

Amor, S. (1995) 'Russian Oil Companies: Attractiveness for Western Investors,' in Proceedings of the conference *Trade and Investment Opportunities in the Russian Oil Industry*, London, March 23-24.

Interdepartmental Commission on Program Development (1994) *Energeticheskaya Strategiya Rossii (Osnovnyye polozheniya)*. Moscow, December.

International Energy Agency (IEA) (1994) *Russian Energy Prices, Taxes and Costs 1993* (Paris: IEA-OECD).

Khartukov, E.M. (1995) 'Russia's Oil Prices: Passage to the Market,' East-West Center Working Paper: Energy and Mineral Series, No. 20, September. East-West Center, Honolulu, Hawaii.

Tankaev, R.U. (1995) *Revenue from Russian Crude Export* (Moscow: InfoTEK-Consult), March.

Acknowledgements

The article is based on a study (Khartukov 1995) performed by the author when working at the Program on Resources: Energy and Minerals, East-West Center, Honolulu (PREM EWC). The author expresses his deep gratitude to Dr. Fereidun Fesharaki, Dr. Ronald D. Ripple and Dr. Kennon Breazeale (PREM EWC), Prof. Øystein Noreng (Norwegian School of Management), Guy F. Caruso and Randolf Gränzer (IEA OECD), Isabel Murray (Natural Resources Canada), Dr. Valery A. Nesterov and Tatyana Ya. Bukhtoyarova (RF Ministry of Fuel and Energy), Dr. Tatyana P. Kulakova (MGIMO Center for International Petroleum Business), and Ian Clarke (Bloomberg L.P.) for their encouraging professional interest, valuable advice and informational backup kindly provided during the paper's preparation. Also, the vital computer support and research assistance rendered by Peter S. Kort and Natalia E. Tabachnaya (University of Hawaii), and Dmitry A. Surovtsev (GAPMER/MGIMO CIPB) are highly appreciated.

1995 Carbon Dioxide Fact Sheet

JOHN H. WALSH

John Walsh is an independent energy advisor in Ottawa.

The 1995 issue of the 'Carbon Dioxide Fact Sheet' follows the same format as in the previous year (*Energy Studies Review*, 7:1:77-78, 1995). Energy consumption data for the world and its principal regions and nations is taken from the *BP Statistical Review of World Energy* and converted to emissions of carbon dioxide using standard factors. This well-accepted source of energy statistics is now posted on the World Wide Web at http://165.121.20.76/stattitl.html. Data previously published in the *BP Review of World Gas*, is now incorporated following the discontinuance of the latter publication. The *Review* is normally published in the June following the year under review and so provides a means of estimating emissions of carbon dioxide from the fossil fuels on a consistent basis throughout the world as early as six months after the subject year.

The conversion of one million tonnes of oil equivalent (MTOE), the basic energy unit employed in the *Review*, was taken here as 41.868 petajoules, a slight change from the value used in previous Fact Sheets. The specific factors applied to the three fossil fuels were those employed by the International Energy Agency: for oil — 19.9 million tonnes of carbon (not the dioxide) per exajoule (MTC/EJ); for natural gas — 13.8 MTC/EJ; and for coal — 24.1 MTC/EJ, calculated on the basis of the higher heating value. Should it be desired to express emissions in terms of carbon dioxide rather than the carbon convention used in this note, the factor is 3.67. The limitations on the use of energy consumption data for the estimation of carbon dioxide emissions have been noted previously. (Walsh, J.H. (1993) '1992 Carbon Dioxide Sheet,' *ESR*, 5:2:131-35).

In 1995, world emissions of carbon dioxide increased by 1.4%, while the corresponding primary energy consumption (excluding biomass and non-commercial forms of energy as is the practice in the *Review*) grew 1.8%. The fossil fuels accounted for 90.0% of the world's

Table 1: Carbon Dioxide Emissions from Selected Countries and Regions

	1994				1995				% Change and C Per Capita		
Country/ Region	Oil MTC/%	Nat.Gas MTC/%	Coal MTC/%	Total MTC/%	Oil MTC/%	Nat.Gas MTC/%	Coal MTC/%	Total MTC/%	% In-crease	% of World	Tonnes C/Person
World	2657 44.9%	1062 17.9%	2205 37.2%	5924 100%	2689 44.8%	1088 18.1%	2231 37.1%	6008 100%	+1.4%	-	1.05
Canada	65.6 51.6%	36.9 29.0%	24.7 19.4%	127.2 100%	66.7 51.2%	38.6 29.7%	24.9 19.1%	130.2 100%	+2.4%	2.2%	4.40
U.S.A.	674.7 45.5%	310.7 21.0%	496.9 33.5%	1482.3 100%	672.2 45.0%	323.3 21.6%	498.9 33.4%	1494.4 100%	+0.7%	24.9%	5.66
E.U. (15)	499.3 56.4%	146.8 16.6%	239.1 27.0%	885.2 100%	504.2 56.3%	156.9 17.5%	234.1 26.2%	895.2 100%	+1.1%	14.9%	2.31
E.Eur. + FSU	247.7 27.2%	316.4 34.7%	346.7 38.1%	910.8 100%	237.1 27.4%	305.1 35.2%	323.4 37.4%	865.6 100%	-5.0%	14.4%	2.03
Austra-lia	28.3 36.6%	10.1 13.0%	39.1 50.4%	77.5 100%	29.3 35.8%	10.4 12.7%	42.3 51.5%	82.0 100%	+5.8%	1.4%	4.48
Brazil	54.8 81.1%	2.4 3.6%	10.3 15.3%	67.5 100%	58.3 81.6%	2.5 3.6%	10.6 14.8%	71.4 100%	+5.8%	1.2%	0.44
China	124.7 16.6%	8.6 1.2%	618.1 82.2%	751.4 100%	131.2 16.6%	9.1 1.2%	646.1 82.2%	786.4 100%	+4.7%	13.1%	0.65
France	73.5 71.0%	16.1 15.5%	13.9 13.5%	103.5 100%	74.2 71.1%	17.1 16.4%	13.1 12.5%	104.4 100%	+0.9%	1.7%	1.80
India	56.1 29.5%	9.1 4.8%	124.7 65.7%	189.9 100%	60.4 30.3%	9.8 4.9%	129.5 64.8%	199.7 100%	+5.1%	3.3%	0.21
Japan	223.6 66.2%	31.4 9.3%	82.7 24.5%	337.7 100%	222.7 65.3%	31.8 9.3%	86.6 25.4%	341.1 100%	+1.0%	5.7%	2.72
Rest-of -World	682.4 62.4%	189.5 17.3%	222.1 20.3%	1094.0 100%	706.6 61.9%	200.8 17.6%	234.3 20.5%	1141.7 100%	+4.4%	19.0%	0.52

energy consumption in that year. As listed in Table 1, Canadian emissions increased 2.4% and accounted for 2.2% of the world's total. Canada's per capita emissions of 4.40 tonnes C/person/year were narrowly exceeded by Australia (4.48), but both countries' per capita emissions were less than the US value at 5.66.

Emissions continued to decline in Eastern Europe (a category here that includes all the former members of the old Soviet Union), but at -5.0%, the rate was significantly less than the -8.9% experienced the previous year. The 15 nations of the European Union also experienced an increase of 1.1% in emissions in 1995 in comparison with a slight decline of 0.1% the previous year. France, though a member of the EU, was listed separately because of the importance of nuclear power in the generation of its electricity: this country experienced an increase in emissions of 0.9% in 1995. In both Canada and France, natural gas was a larger source of carbon dioxide emissions than coal. The United States remains the largest contributor to emissions, accounting for 24.9% of the world's total.

The growth in emissions in the large developing countries of Brazil, China, and India is noteworthy at 5.8%, 4.7%, and 5.1% respectively, although their per capita levels remain low. In the rather heterogeneous category of the Rest-of-World (calculated by deducting all the countries or regions specifically listed in Table 1 from the world total), emissions rose 4.4%, but per capita emissions were low at 0.52 tonnes C/person/year. Primary energy consumption increased in some nations in Eastern Europe in 1995 (Hungary, Romania, Slovakia), and it is clear that if economic conditions improve more generally throughout this region, world emissions of carbon dioxide will increase more rapidly.

International negotiations aimed at the mitigation of greenhouse gas emissions continue under the Framework Convention on Climate Change with a Second Conference of the Parties scheduled for July 8 -19, 1996, in Geneva. The Department of Natural Resources issued a study of Energy Efficiency Trends in Canada dated April 1996, which identifies and analyses the factors relevant to changes in the demand for energy and reports progress on the development of efficiency indicators.