# ENERGY MARKET REFORM

Lessons Learned and Next Steps with Special Emphasis on the Energy Access Problems of Developing Countries

A Report of the World Energy Council

**AUGUST 2004**

**ENERGY MARKET REFORM**



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United Kingdom
www.worldenergy.org

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# TABLE OF CONTENTS

Page

# FOREWORD

The terms of reference for this report, one of the main outputs of the World Energy Council's 2002-2004 global studies programme, state:

> "…It is now time to draw practical lessons from these [past WEC] studies and current experiences on the desirable architecture of market reforms in electricity and natural gas...the approach will not be to further deepen the analysis or to provide technical recommendations but to build a debate guided by the common thread of energy security and end-user "empowerment", highlighting the possible areas of conflict of interest and what broad solutions may be chosen depending on the local circumstances for the different parts of the energy chains…the ambition is to identify what the key concerns should be and to initiate a debate on what the possible answers are…the objective is to have a final report that reflects this debate and to pursue and develop it during the Sydney Congress as one of its major themes..."

The intentions expressed in these lines have been confirmed during the three years of work on the study by the chairman of the study, Dr. Pablo Mulás, and the Study Group which supported him. The four topics that were envisaged in the terms of reference and which now form the core of the report are *Empowering End-Users* (Part I), *Security of Supply, The Wilder Challenge* (Part II), *Wholesale Market Design* (Part III), and *Tariff-Setting & Energy Poverty* (Part IV). The Study Group has identified the key issues for each of these topics and summarised them at the end of each section. In terms of global recommendations, there is no overriding conclusions except that local circumstances are critical, and there is no "silver bullet" for energy market reforms which can be applied to every market. For this reason, the Studies Committee has elected not to publish an Executive Summary for this report.

A few broadly applicable messages do flow from the analysis and must be kept in mind:

- Market reforms in energy systems are needed because organisations and work methods need to evolve as society and the business environment change;
- Successful energy market reforms are only a subset of the broader reform agenda, in particular, for the reliance on domestic capital markets;
- Regional integration is one of the surest means to reduce regulatory uncertainties and provide a larger market with economies of scale;
- Market design is a matter of local and regional circumstances; in the latter case, there is a need for agreement among the countries concerned to proceed in common;
- Lastly, there is no perfect model to address all market circumstances, but as WEC has already said in previous publications, governments and regulators need to compromise in favour of simple, robust, evolution-prone designs.

I believe that, as such, this study brings a very useful contribution to the current debate on energy market reforms. On behalf of the Studies Committee I wish to thank Dr Pablo Mulás from Mexico, chairman of this study, the members of the Study Group (see Annex B), and the coordinator of the study, Jean-Marie Bourdaire, who has been instrumental in carefully balancing the final text between analysis of the past and opening new roads for the future.

François Ailleret
Chairman of the Studies Committee
August 2004

# PREAMBLE

## Past WEC Messages

In the 2000 WEC Annual Statement *Energy for Tomorrow's World - Acting Now!* (ETWAN), the very first recommended action was "Reap the Benefits of Market Reform and Appropriate Regulation". It was summarised in the following way:

> "*As a general rule, governments need to withdraw from directly managing energy markets and should restrict their role to setting sound rules administered by impartial regulators. The key words are liberalisation, trade, privatisation, and more generally customer choice. Market reforms should take into account the growing link between gas, liquids and electricity. The agenda for reforms needs to be clear and implemented within a reasonable timeframe in order to lower the transition costs, in particular because of the increased uncertainty that market reforms imply. Appropriate and balanced regulations set and implemented by impartial bodies independent of short-term political interference are essential"*.

Market reforms were also mentioned in five other actions out of the ten proposed by ETWAN:

- Number 2: Keep All Energy Options Open;
- Number 3: Reduce the Political Risk of Key Energy Project Investments;
- Number 4: Price Energy to Cover Costs and Ensure Payment;
- Number 5: Promote Greater Energy Efficiency;
- Number 7: Ensure Affordable Energy for the Poor.

WEC has published a number of important reports which touch on energy market reform:

- *Benefits and Deficiencies of Energy Sector Liberalisation*, published in 1998 for the 17th World Energy Congress in Houston. It is an exhaustive summary of the benefits and risks of energy sector liberalisation in 33 countries and regions, to be updated to cover over 100 countries, with all the information available electronically from WEC's Global Energy Information System.
- *Emergency Energy Legislation in Central Europe: Market Orientation, International Compatibility, Business Implications*, published in 1998 on energy sector legislation in Central and Eastern Europe.
- *Electricity Market Design and Creation in Asia Pacific*, published in 2001, a challenging and innovative approach to the questions of privatisation and workings of wholesale markets.
- *Energy Markets in Transition: The Latin American and Caribbean Experience*, which was published at the 18th World Energy Congress in Buenos Aires in 2001 and which extends the discussion to employment, social and other impacts.

These studies have been taken into account in the preparation of this report. One of the major outcomes of the Buenos Aires World Energy Congress in 2001 was the decision by WEC to focus on what appropriate energy market regulation might look like, particularly as it relates to investor-friendly energy policy and regulations which can help finance new infrastructure to provide secure capacity or access to energy services in both developed and developing countries. Follow-up work in 2003 for South Asia (Bangladesh, India, Nepal, Pakistan, and Sri Lanka), including a regional workshop held in February 2003 in Colombo on electricity market reforms, has also helped shape the analysis. All these studies provide useful background thinking on the design of energy market reform, especially in developing countries. They all come to similar conclusions that are summarized in the following box:

**Energy market reforms need to:**
- **Examine the competitive potential of each stage of the energy chain, not just upstream activities such as electricity generation or natural gas production and imports;**
- **Ensure that benefits are commensurate with costs for each stage of the proposed reforms of the electricity and/or natural gas system; and,**
- **Respect the limitations of competition and the costs (economic or social) that it generates and, given the potential risks and costs, focus on simple choices.**

**The Situation Today**

Many countries, mostly developed, have started the process of reforms with mixed results. Concerns have arisen because of the evidence of market failures or near failures and the often underscored cost of uncertainty. Political and/or regulatory instability has significant direct and indirect costs, for instance, higher rates of return and reduced debt leverage resulting in non optimal choices.

The need for a stable institutional framework was recently mentioned by the Energy Commission of the International Chamber of Commerce:

> *"In order to marshal significant private (as well as institutional) investment funds, a basic framework to ensure security and predictability of the investment must be in place:*
> - *Political and economic stability to provide reasonable predictability for making business decisions and mitigate unacceptable levels of risk;*
> - *Governments which basically facilitate doing business, and eschew harassment and arbitrary intervention;*
> - *Presence of a functioning legal framework and process, security of property and persons, enforceability of contracts, and reliable dispute settlement frameworks;*
> - *Sound economic and financial frameworks, including currency convertibility, freedom to remit dividends and other investment proceeds;*
> - *Rational price, tax and subsidy policies, and a regulatory regime which is independent of the political process;*
> - *Fundamental business ethics, including the avoidance of corrupt practices;*
> - *Capacity to supply technical skills, goods and services, through the movement of goods and people, and a trainable workforce."*

In addition, there needs to be increased awareness that energy market regulations are only a subset of the broader institutional setting: property rights, rule of law, taxes and their collection, reliance of citizens on the domestic financial institutions and an equitable society without which economic development cannot be undertaken collectively are also part of the reform agenda. Here too stability is needed because trust and confidence have to be built over a longer, stable period during which all those involved in the market or the economy at large see the real and potential benefits to them. In turn, such stability will only be achieved if there is a consensus on a common and simple vision in the country or the region which underpins energy market reform. "Vision" covers the minimum to be done and, if compromises have to be made, what, why and how the corresponding issues need to be addressed. These compromises are often called trade-offs.

Such trade-offs cover many issues that go beyond the energy context. For instance, the question of whether investment is domestic or foreign is of fundamental importance for developing countries if the aim of reforms is, *inter alia*, to rely on private capital. Some trade-offs are energy-specific because the provision of electricity and natural gas has very precise characteristics:

- On the one hand, because of the peculiar characteristics of energy networks, public monopolies look like the theoretical lowest cost solution to deliver, in principle, maximum benefits including a diverse, resilient, secure and adequate (in terms of capacity margin) supply portfolio;
- On the other hand, monopolies lack competitive incentives and “are to competitive markets what dictatorships are to democratic political processes”[1]. Indeed, competition is the most powerful driver to minimise costs and improve efficiency.

Easily reconciling the theoretical but rarely realised state monopoly’s benefits with those of competition is an ambitious goal. Most industrialised countries have already chosen their model and engaged reforms with a road map for the future. They are not ready yet to consider other approaches, even if their experience has not been an undisputed success. Conversely, developing countries are keen to avoid costly experiments but need to fulfil their rapidly growing energy requirements despite immature or nonexistent institutional frameworks. They know that reforms are indispensable because of the indisputable benefits of competition but remain cautious about going too far in uncharted waters; they do not want to experience the high costs and major failures that have happened or might still happen in some developed countries. Simplicity, robustness and low-cost are their key words.

**Why a New Study?**

For countries which have undertaken energy market reform but now doubt its wisdom or the directions they have taken, as well as for many developing countries willing to begin the reform of their energy markets because they see it as one of the key means of achieving access to energy services for their people, there is a debate fed by the WEC reports described above and by the variety of views expressed by WEC members and other experts, be they the privately owned energy industries in the developed countries or their often state-owned counterparts in the developing countries. This debate is the cornerstone of this report. It is guided by the common thread of improved efficiency, lower costs, guaranteed energy security and end-user “empowerment”, including energy access to the poor. It is based on currently available experiences and highlights the role of national circumstances, the possible conflicts of interest and the need to make trade-offs at critical times and in critical areas.

Three particular aspects of energy market reform are given special attention in this report:

- First, some unknown territories remain: the evolution of the interface between natural gas and electricity reforms given the growing appeal of gas turbines, their benefits for mid or peak load generation and therefore the notion of “convergence” between natural gas and electricity;
- Second, some other territories are partly new to WEC: the downstream reforms to reduce costs and draw the benefits of competition in distribution, the economies of scale and scope (another domain for “convergence” with the concept of “multi-utilities”), the need to address security and diversity of supply explicitly and the “Damocles sword” of market power;
- Third, some early experiments with market reform need to be reconsidered: when going private, should a country rely on foreign or domestic private capital? How should a country deal with the stranded costs or the natural rents of some investments? How can pricing be

[1]WEC 2001 Congress in Buenos Aires, Minister of Energy for Uruguay

cost-reflective to sustain the long-term supply and still provide for affordable energy services for the poor?

The report covers these different aspects as well as the trade-offs that network energies require because they gather monopoly elements (the grid) and captive consumers together with competitive elements. After an introduction devoted to the workings of gas and electricity and their rapid convergence, energy market reforms are discussed under four headings, corresponding to the four parts of the study:

- Part I is dedicated to the empowerment of end-users, thus underlining the critical yet often forgotten importance of distribution (and of retail supply);
- Part II examines the question of security and how a competitive market can bring enough capacity on time with sustainable diversification;
- Part III is about market design. As earlier WEC studies have confirmed, no system is perfect, and trade-offs depending on national circumstances need to be made;
- Part IV addresses the question of pricing and sustainable tariffs with special attention to the challenge of affordable access to energy services for the poor.

The treatment of these four key topics is long and complex because many aspects of market reforms are closely interwoven. The fact that no theoretical ideal system exists and that, in certain domains such as the organisation of the distribution sector, there is very little empirical data, adds to the complexity of the analysis. Last but not least, what has worked in a certain context and in specific circumstances has no universal value because different trade-offs could have brought a similar efficiency or because, if it were blindly applied to another country, it might not work well.

Because of the many aspects of energy market reform and the complexity of problems encountered, this report sometimes ventures into uncharted or controversial areas. As it stands, it reflects the many debates within WEC and with outside experts without necessarily drawing conclusions and recommendations. It is not a unanimous WEC publication but rather, it provides grounds for future work, either to improve the process of reforms in countries that have already moved ahead or to discuss what the agenda for new reforms should be, especially at the regional level and in developing countries which have not yet begun the process in a serious way. The effort to regionalise the analysis of this report could, therefore, be part of the WEC Studies Programme for 2005-2007.

## INTRODUCTION

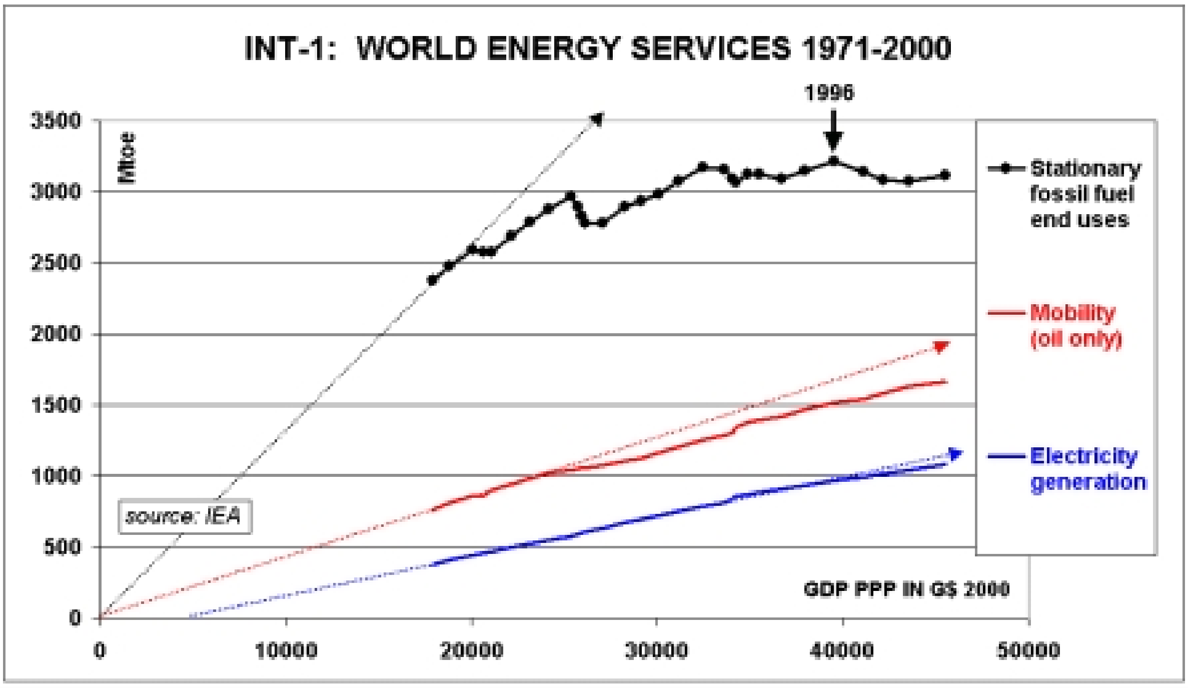
### 1. Dynamics of Electricity and Natural Gas

Energy is a key input to economic welfare, with a role possibly ten to twenty times larger than its sectoral share of gross domestic product (GDP) suggests. Its contribution over time to GDP has followed a two-fold trend: productivity increases (a declining amount of total primary energy - including the share of non-commercial fuels - per unit of GDP) and fuel portfolio evolution (from biomass to coal, to oil and now to natural gas and electricity).

Within the mix of primary energy sources at the global level, the share of natural gas has been growing at the expense of oil and coal, but the share of non-commercial fuels has now stabilised after a long secular decline over many years until roughly the 1970s. In terms of final energy demand, stationary fossil fuel end-uses have lost ground to mobility and electricity services. Part of these trends is structural and reflects the process of economic development, while part is triggered by price changes and remains locked in the stock of capital. Of particular relevance for market reforms is the growth of natural gas in the electricity sector.

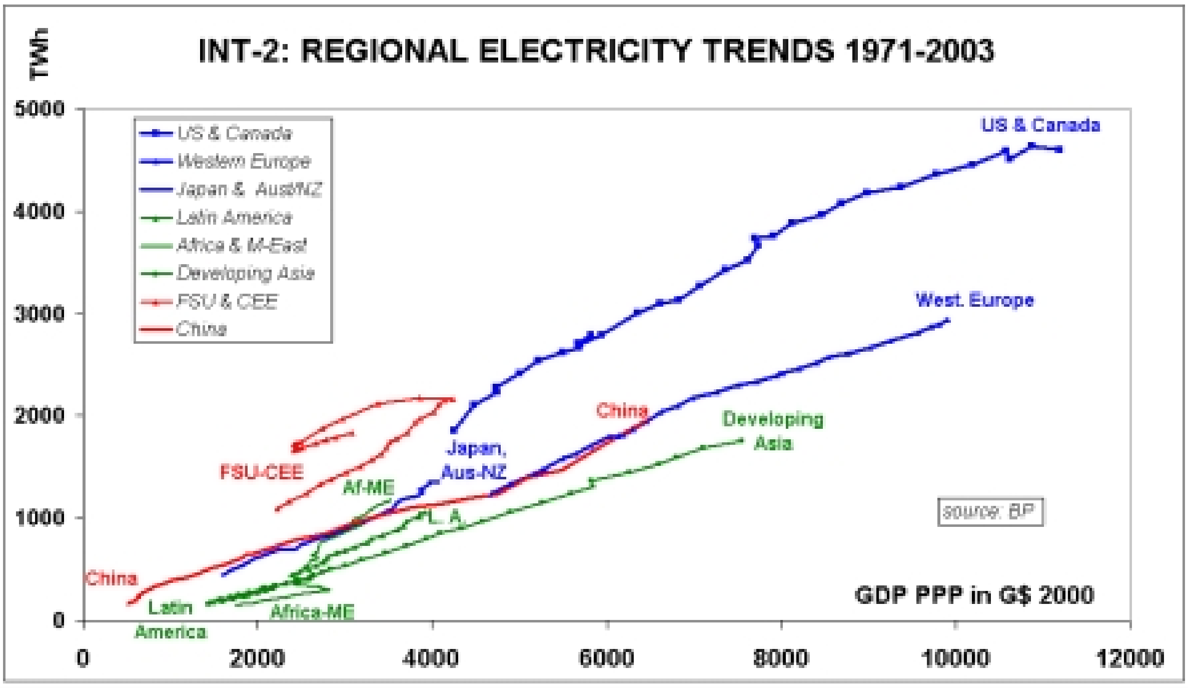
The evolution of electricity supply and demand was identified and analysed by Chauncey Starr, the first chairman of EPRI (Electrical Power Research Institute) in the USA, and his colleague Milton Searl in *Revue de l'Energie*. It was broadened to the whole energy sector in the recent WEC publication, *Drivers of the Energy Scene*, published in December 2003, which shows, in particular, the key role played by energy in the dynamics of economic development (an aspect also much emphasised by the World Bank).

In a market in equilibrium, all economic inputs (labour, capital, energy, raw materials, etc.) have equal marginal economic productivities. When the economy grows, if the input productivities were not to grow at the same pace, the one with the lowest value (for instance, energy, if its relative price rises) would become the limiting factor to GDP growth. To avoid that, low energy prices have been of critical importance. This means, in turn, that security of supply (the addition of new capacities timed to keep pace with energy demand without increasing energy prices) is central to stable economic progress.



***Electricity*** plays a pivotal role in these dynamics. Its evolution is tightly linked to GDP, demonstrating that "electrification" is a driver of development and the lack of access to it is one of the characteristics of under-development. The regularity of national or regional electricity demand trends compared with the trend in GDP when the average end-user price is unchanged over time, as well as the inverse relationship between electricity demand per unit of GDP and the average end-user price, highlight the critical role of final energy prices. This is shown in Graph 1.

In economies in transition and the Middle East, macro-economics have changed significantly (after 1989 in the Former Soviet Union (FSU) and Central and Eastern Europe (CEE), after the end of the cultural revolution in China around 1978 and after the oil price shocks of the 1970s in the Middle East). The corresponding electricity trends in these regions are, as shown in Graph 2, still unclear. In the other regions, nearly unchanged electricity prices (in constant dollars), even at the time of the oil shocks, explain why the electricity trends are regular, nearly linear, in relation to GDP. The rate of increase of electricity demand varies from region to region, but it is inversely related to average final prices and over time approaches a long-term final price elasticity close to 1.

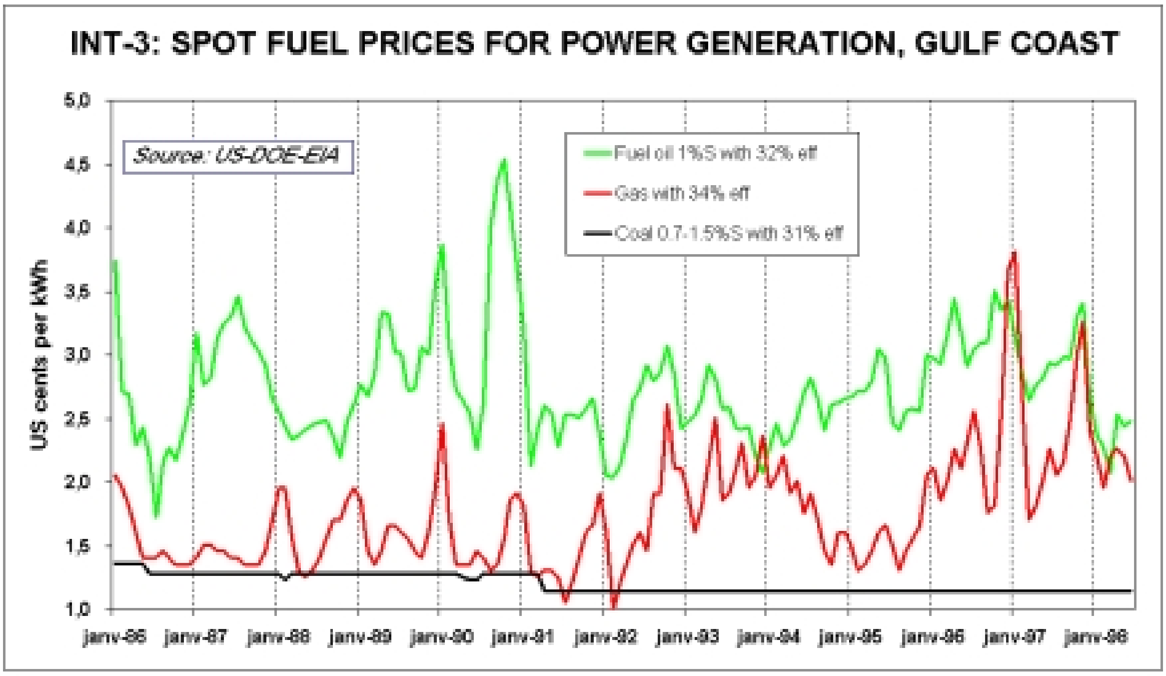



***Natural gas*** is important because of its significant and growing share in power generation. The low costs and high efficiency of the new combined cycle plants and combined heat and power plants as well as the constraints faced by coal, large hydro, nuclear and new renewables make natural gas and CCGT the most frequent choice for new power plants. Because of this growing role of natural gas supply in the generation of electricity, regulatory reforms have to ensure that security of supply of both natural gas and electricity is not put at risk. The short-term benefits of lower prices should not undermine the reliability, diversity and growth of long-term supplies. It is of utmost importance, in electricity terms, that governments and regulators understand the price-setting mechanisms in competitive natural gas markets.

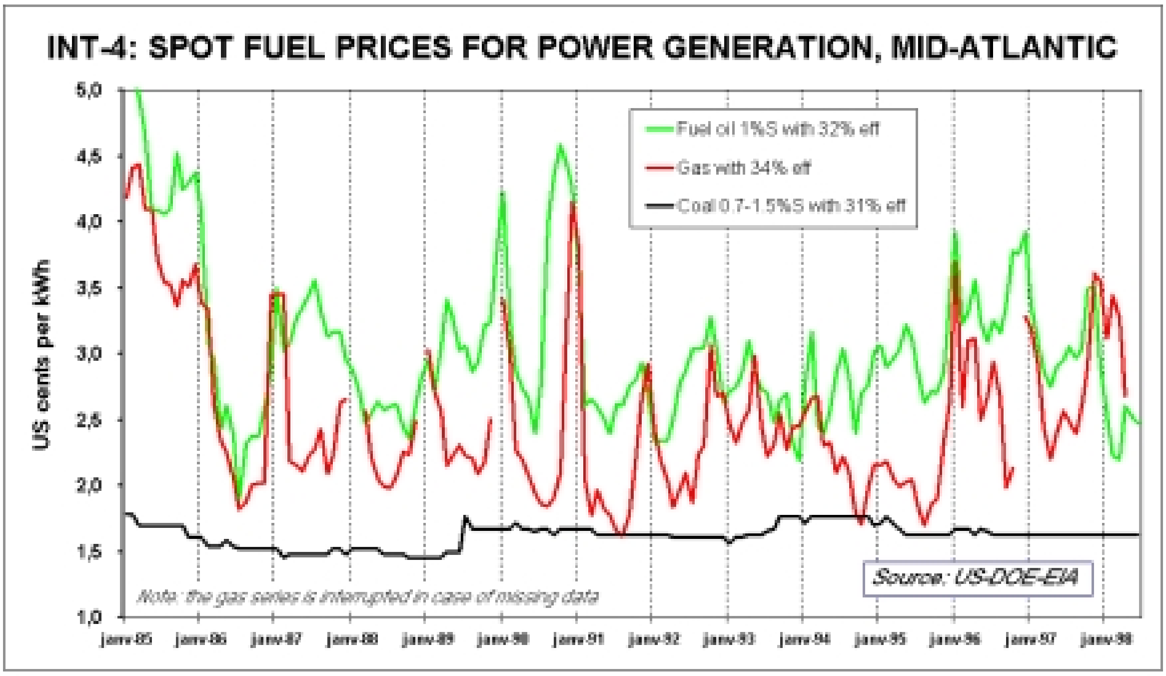
## 2. The Role of the Power Sector as a Price-Setter of Natural Gas

Natural gas has no captive market because its users can switch, sooner or later, to a competing fuel. This competing fuel "at the margin" in dual-fired boilers or turbines will be the price-setter of gas. Given that industrial fuel demand is flat (base load), whereas the demand for electricity is variable (due to day/night and seasonal patterns), power plants play a key role in the competitive price-setting of natural gas, more so because gas or petroleum fuels have high variable costs and are run for mid or peak load (i.e., for variable uses, unlike coal, hydro, or nuclear, which have low fuel costs and are used for base load electricity generation). The electricity sector is therefore at the heart of inter-fuel competition and the setting of natural gas prices.

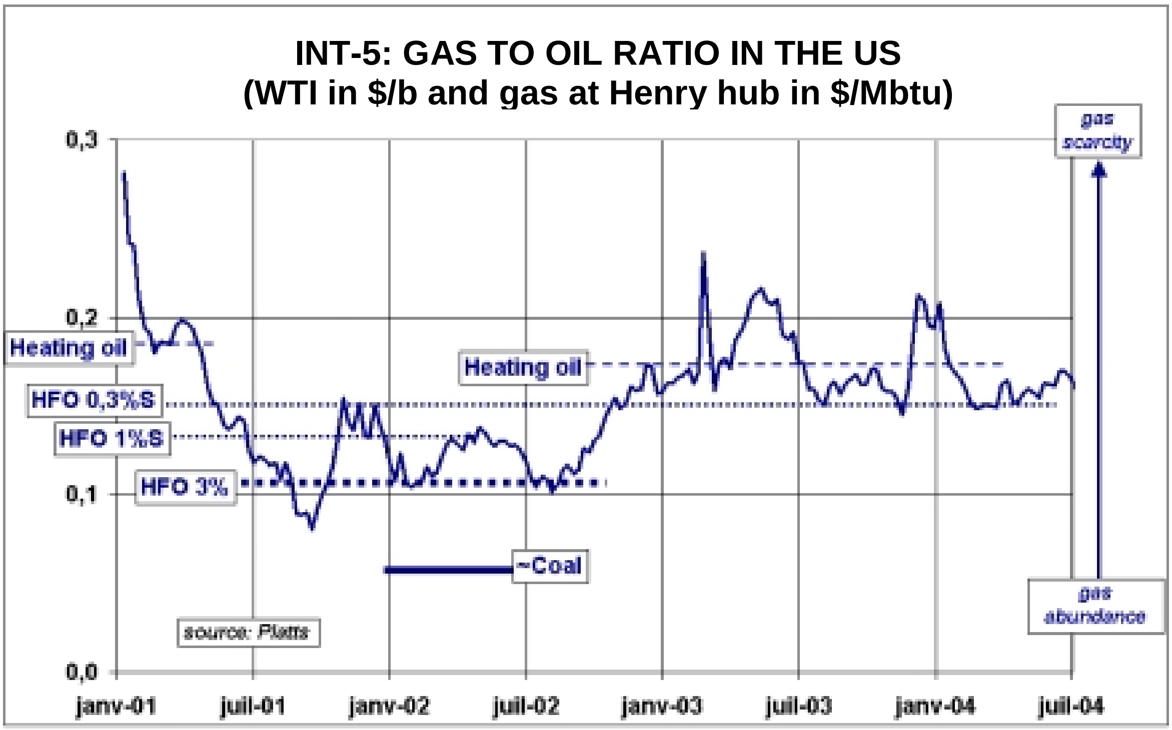
Graph 3 shows US gas priced against coal in the "bubble" periods when gas was so abundant that it substituted for all switchable petroleum products and had to compete against coal on a kWh basis. Given the slightly better efficiency of gas, at $1.2/1.3/Mbtu, its price was equivalent to a spot price for northern coal shipped to Texas at $35/tce at the burner tip. This happened in the south during most summers of the 1986-1992 period.

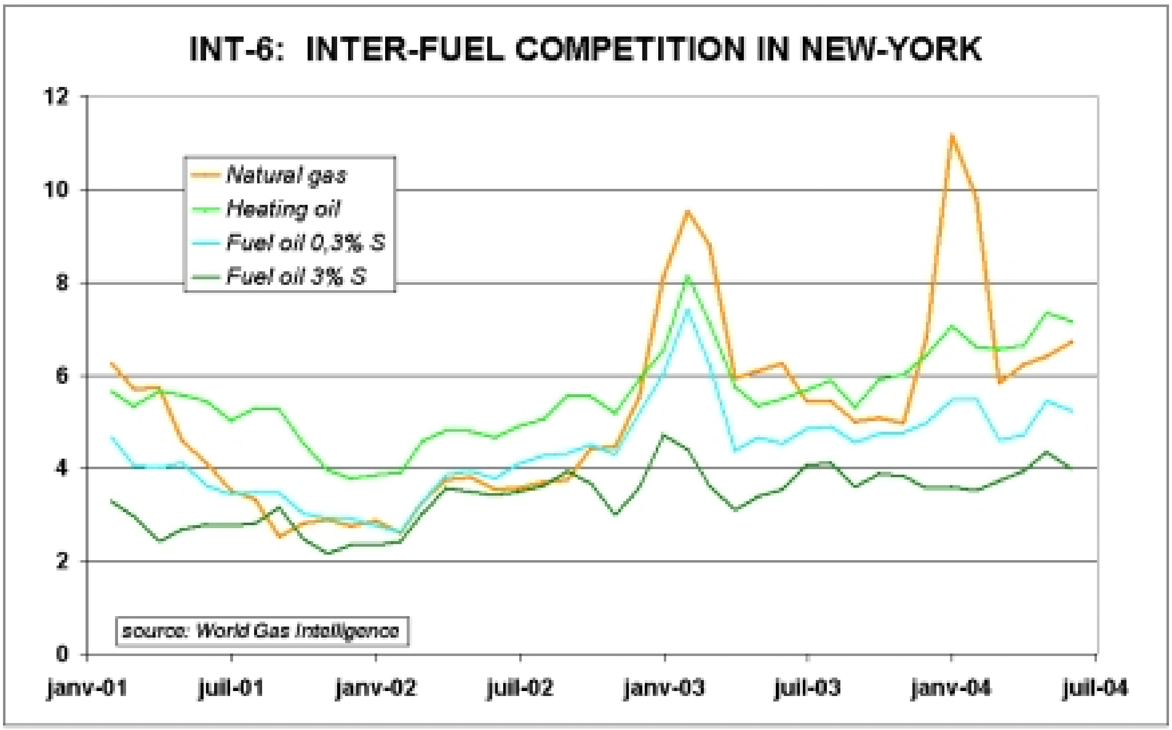



Graph 4 shows US gas priced against heavy fuel oil (HFO) when gas is less abundant, i.e., when all dual coal-gas burners are switched to coal. The gas price is then set at the burner-tip of the dual-fired boilers against HFO cost on a kWh basis (thus taking stock of the 5% better efficiency and lower variable costs of gas). This happened during most winters in the northeast region.

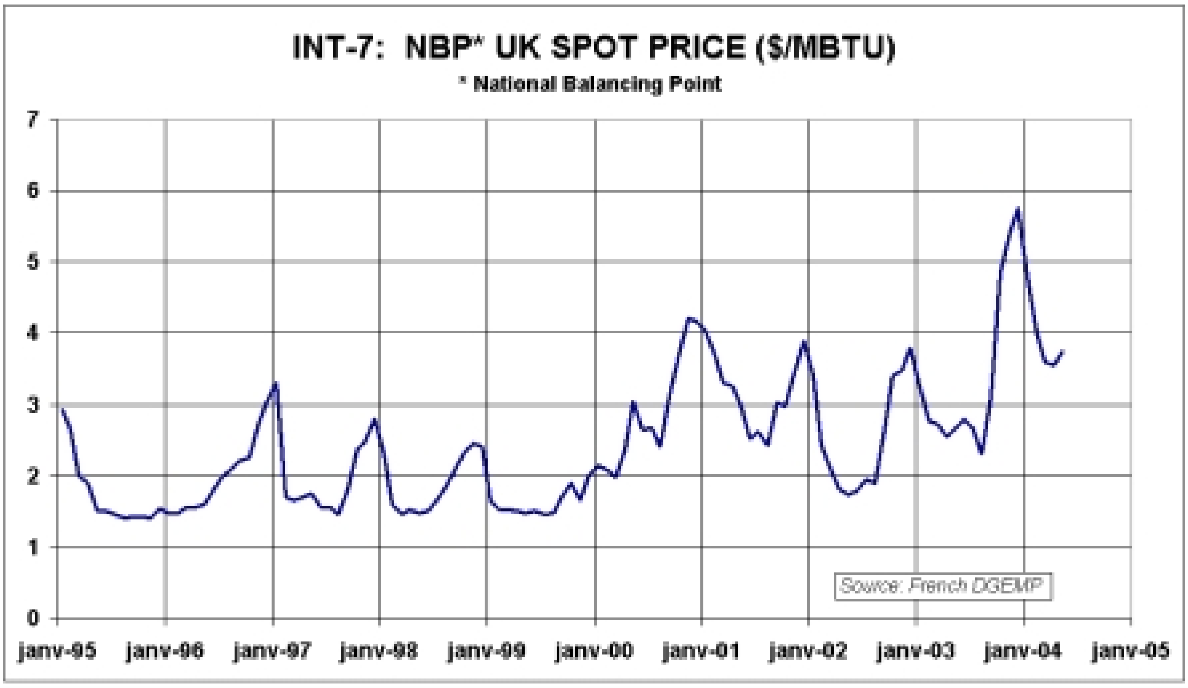


If all dual-fired gas/heavy fuel oil (HFO) plants switched to HFO because gas was scarce (due to declining domestic supplies and/or strong winter gas demand for captive consumers), the gas price would rise to the next marginal fuel, which is oil distillates used for clean boilers or in turbines. This occurred in the USA between February and April 2001 and during most of 2003. With even scarcer gas, and all dual-fired capacities switched to other fuels, the gas price would skyrocket to the level of penalties that apply to distribution companies when they cannot serve their captive customers, say, $50-70/MBtu in the case of the USA. This happened several times in 2003 and 2004 as highlighted in Graphs 5 and 6.



Another example of a fully competitive natural gas market is that of the UK since the emergence and dominance of the spot market early in 1995. Graph 7 shows successive gas-to-coal competition at $1.5/MBtu during summer, when gas is abundant, and gas-to-HFO competition in winter, when gas becomes scarcer because of the high seasonal demand. It also shows that spot prices had a regular seasonal pattern when the interconnector pipeline was not yet open, after which the possibility of arbitrages between the UK and continental Europe resulted in a more random pattern from 1999 onwards.




Thus the gas price is set on the basis of the variable fuel cost (per kWh output) in the power sector. It can be equal to its marginal competitor or it can oscillate between the prices of different competing fuels such as:

- A floor set by coal and the heavy fuel oil ceiling in periods of bubbles;
- A floor set by heavy fuel oil and the heating oil ceiling in normal supply circumstances; or
- Above the heating oil floor in periods of scarcity.

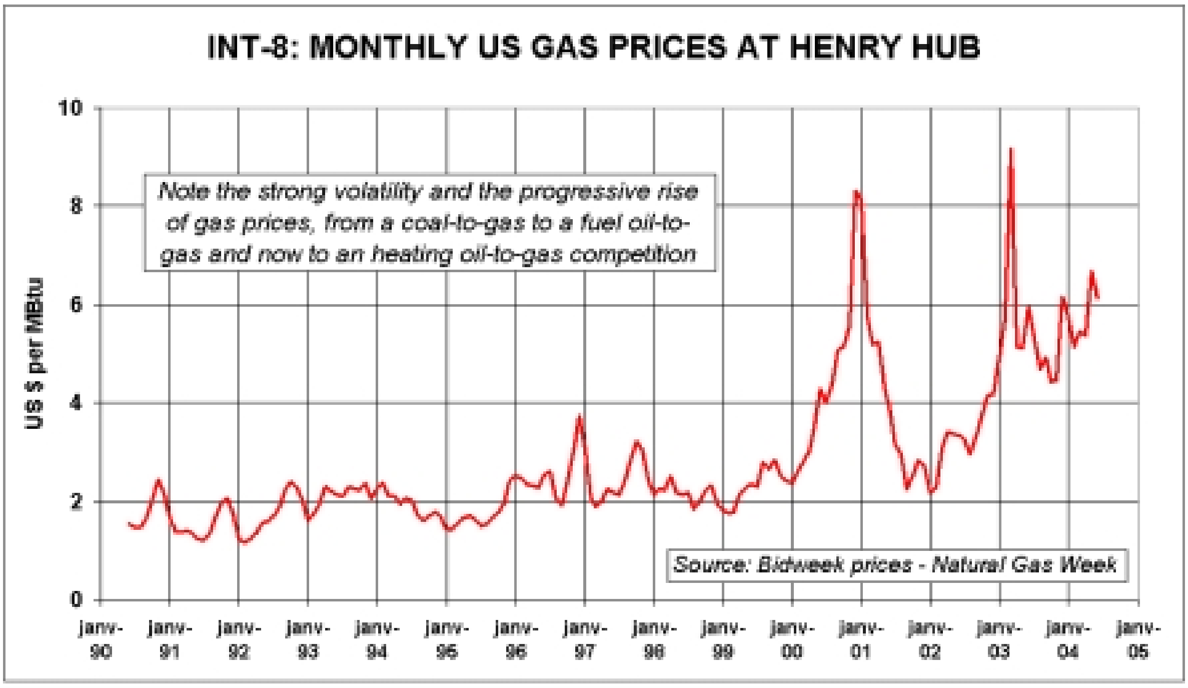
**3. The Key Role of Interruptible Customers**

More recently, since the winter of 2003, a new phenomenon has emerged because of the decline of UK domestic gas production and the need to import at the margin when winter demand increases beyond the domestic supply capabilities. This new high price has two different yet closely linked causes:

- The "drying up" of interruptible capacities, which pushes gas prices to the next competition level beyond heavy fuel oil, that of the oil distillates (heating oil); and,
- The beginning of inter-regional LNG arbitrages between the US Lake Charles re-gasification terminal and the Zeebrugge re-gasification terminal in Europe, where the inter-connector pipeline mentioned above terminates. With these arbitrages, the high US gas price and volatility are "exported" to Europe.

What creates the link between these two causes is the fact that the high gas price and volatility in the USA (see Graph 8) also result from the "drying up" of interruptible capacities in that market. Unfortunately, the statistics regarding the level of interruptibility are very poor and unreliable because the last survey of the DOE-EIA is now ten years old. In that decade, many interruptible customers disappeared because of environmental constraints that prevent the use of heavy fuel oil.

Since, in addition, most of the 200 GW of newly built CCGT cannot switch to distillates, the price of gas has no cap (as it did in the New York market as shown in Graph 6).

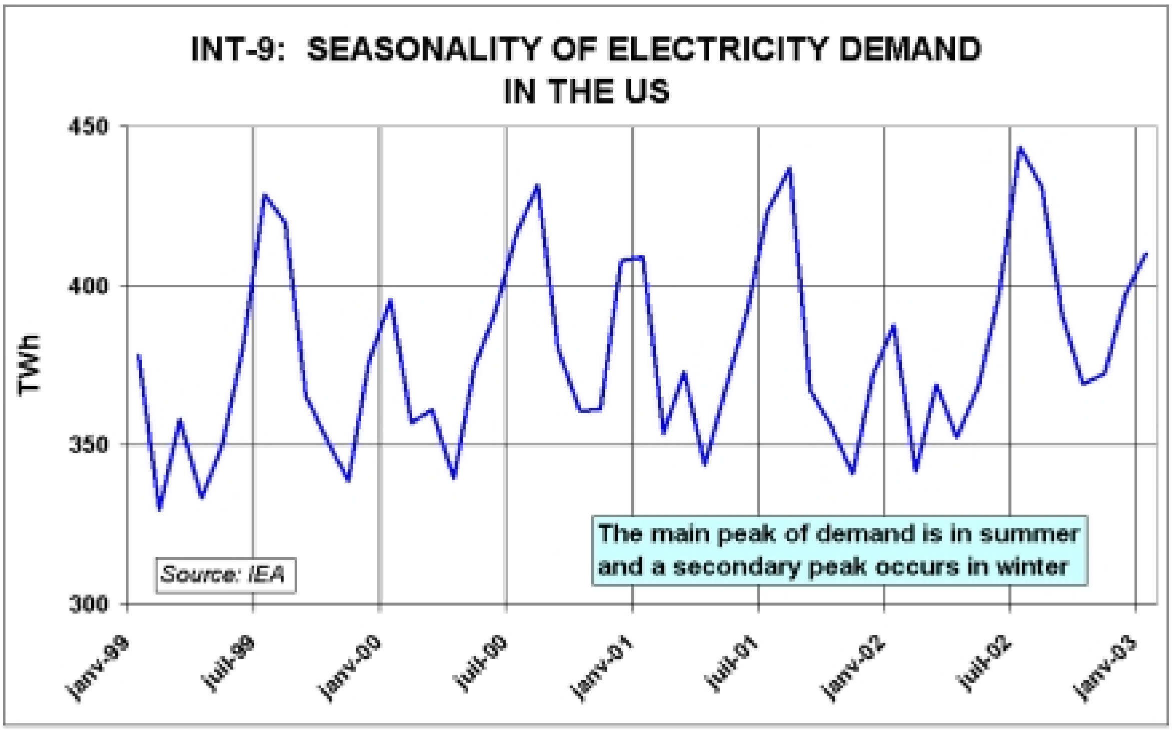



The only way to keep natural gas prices stable or predictable, avoid the enormous volatility currently seen in the USA and ensure a smooth long-term security of natural gas supply is to make certain that enough interruptible capacity exists against heavy fuel oil in industrial use and against distillates (with dual-fired turbines) in the power sector where CCGT is taking a sizable share of the electricity market. This is a responsibility of government energy policy and the regulations which flow from it and as such, both the policy and the regulation need to address natural gas and electricity markets together.

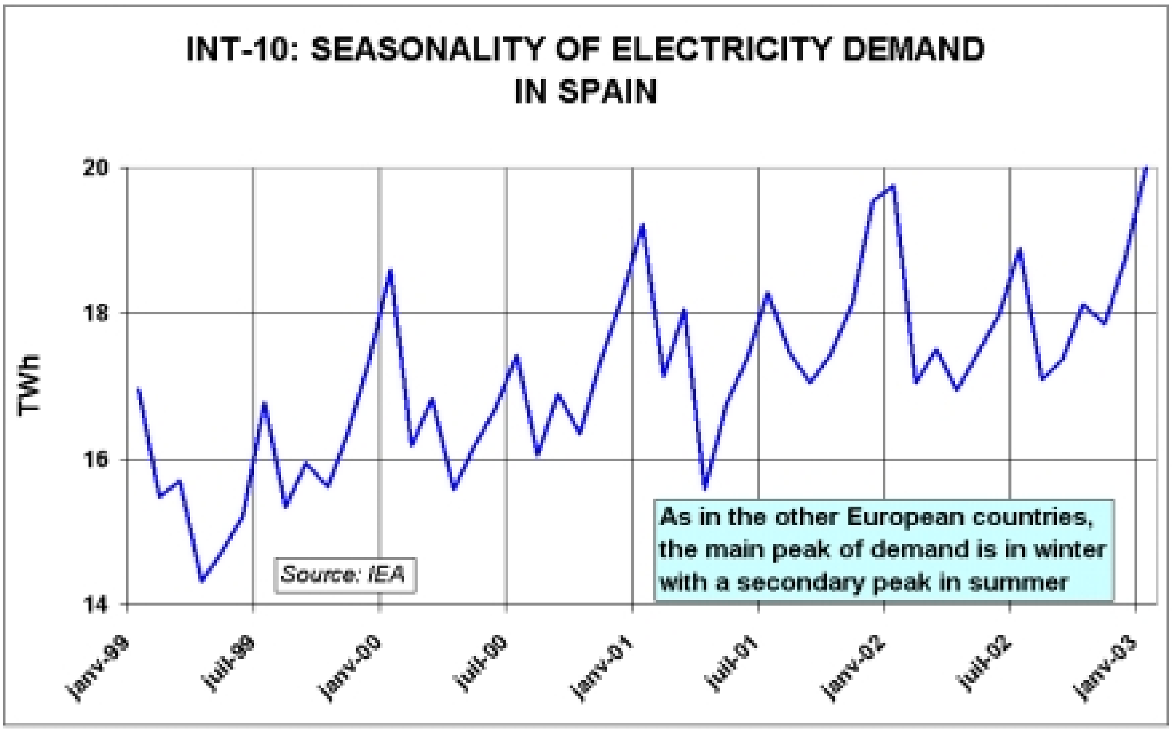
## 4. The Nature of Electricity Demand

Electricity demand varies during the day (day/night patterns), the week (higher during working days) and the year (seasonal fluctuations) and is described in Graphs 9 and 10 highlighting the differences between North America and OECD Europe. This variable demand is described by the load curve, which is filled by power supply according to the merit order. For the short-run workings of the electric system, capital costs do not matter, and the power plants are run on the basis of their variable cost, i.e., the fuel cost per kWh produced, with natural gas (except during the periods of "bubble") and petroleum fired plants normally being the most expensive fuels and therefore the last to be called "at the margin".

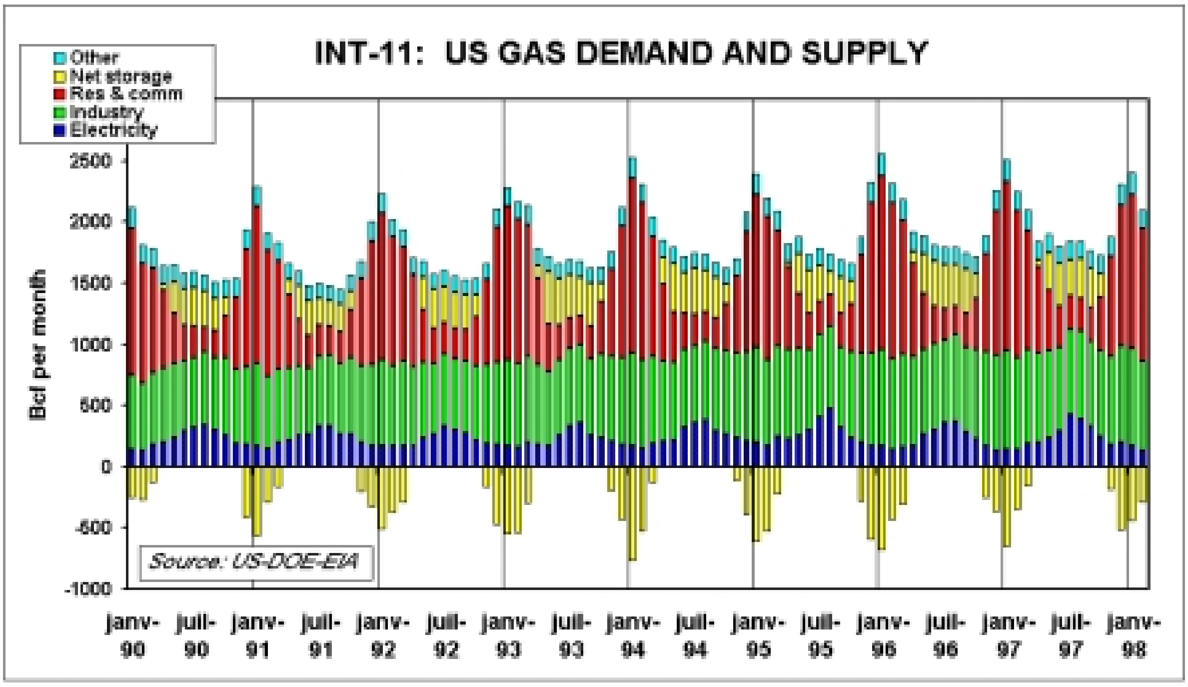
North America and OECD Europe display different and, to a certain extent, complementary seasonal fluctuations. North American demand peaks in summer, as it does Japan (which represents 60% of OECD Asia demand). In Western Europe, demand peaks in winter. Therefore, if natural gas grows in mid/peak load uses as the economics and trends discussed above suggest, the corresponding gas incremental demand will occur in winter in Europe and in summer in North America and Japan. It would then be up to the Middle East LNG producers (and those in Africa to a lesser extent) to arbitrage the destination of their LNG exports on a seasonal basis (providing that enough flexibility exists for the logistics, such as shipping and re-gasification capacities).




However, seasonal arbitrages need to be seen in the broad framework of the gas demand swing, including the captive users of the residential/commercial sector in winter and the need to rely on additional LNG to complement domestic supply and pipeline imports. This is discussed hereafter.



**5. The Seasonal Nature of Gas Demand and the Need for Flexibility**



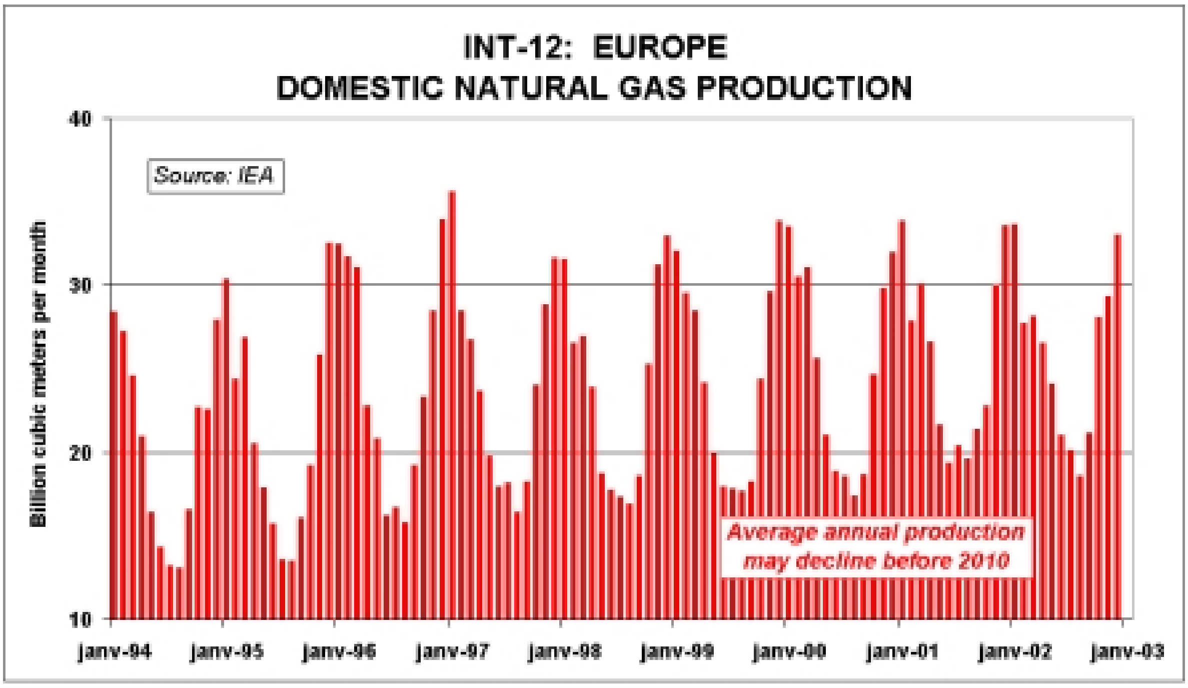

The three countries of North America (Canada, USA and Mexico) face similar supply/demand patterns. For the USA, which represents 85% of the overall North American market, the historic series show that final residential-commercial demand (red) is strongly winter-seasonal, final industry demand (green), which includes the non-utility generators (generally base load CHP schemes), is more or less flat over the year and utility sector demand (black) is strongly summer-seasonal. This last component of demand is poised to grow quickly because natural gas is the fuel of choice for all new power plants.

| **Management of flexibility (IEA 1999 data)** | **North America** | **Europe** |
|---|---|---|
| Consumption swing* | 137% | 152% |
| Supply swing*, of which: | 107% | 125% |
| - production swing* | 105% | 134% |
| - import swing* | Not significant | 118% |
| Geological storage (% of annual consumption) | 17% | 13% |
| LNG storage | 0% | 0% |
| Fuel switching (% of average daily consumption) | 9% | 12% |

* Swing is the peak seasonal value expressed as a percentage of the average annual value

As is clear from Graph 11 and confirmed by the above table, US demand variations are accommodated by storage (build-up in summer, draw-down in winter) without curtailing production (basically there is a flat production profile with about 105% flexibility over the year). Given the contra-seasonality of power sector demand, the growth of natural gas in power generation will reduce the overall demand swing and free the part of seasonal storage used to provide the needed flexibility until now. This in turn will lower the cost of gas storage.

In Western Europe, the situation is quite different. Given the higher demand swing than in the US (152% versus 137%), one would expect a storage greater than the 17% of the US. WEC has calculated that an indicative figure might be 24% if one assumes that the capacity of the storage should be proportional to the seasonality. As the table above shows, Western Europe is far from this storage level, possibly because of the lack of appropriate price signals. Thus the swings in domestic natural gas production and imports in Europe will have to be tackled differently, possibly through LNG arbitrages linking the US and European markets across the Atlantic ocean.



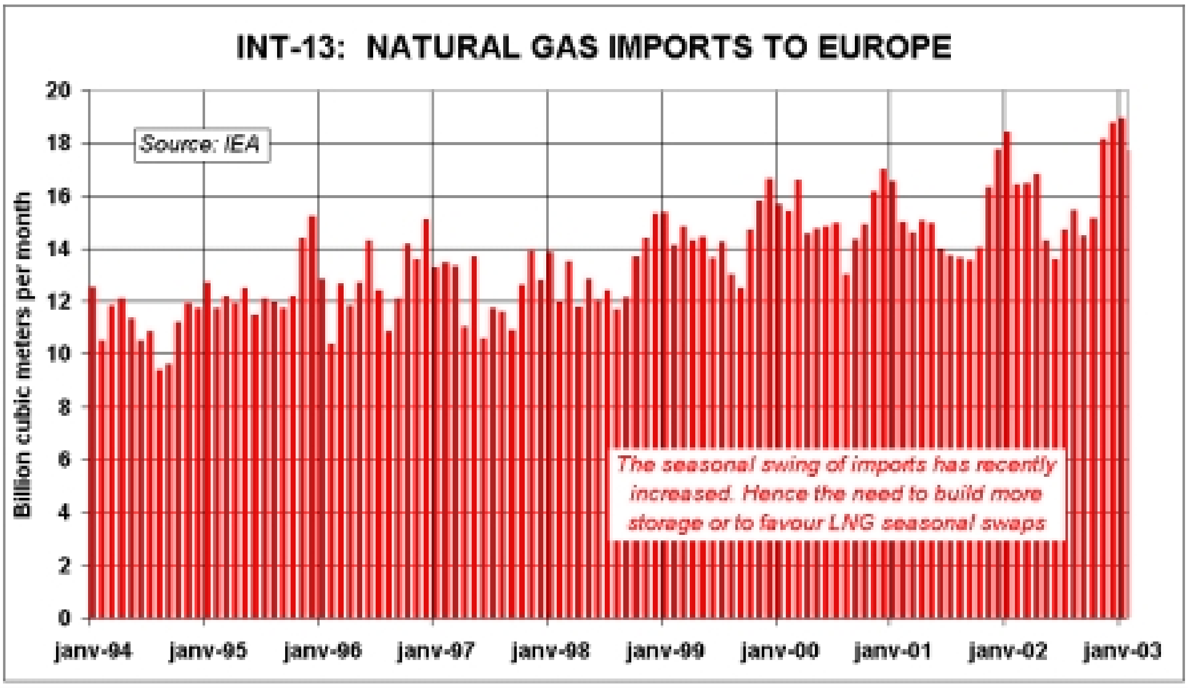

The European situation has, recently worsened because the demand swing has grown due to increased electricity demand, but the ability to vary supply has fallen with the increased maturity of domestic natural gas production. In Europe, unlike in North America, where electricity demand is contra-seasonal and therefore reduces the demand for flexibility, electricity demand peaks in winter, and a higher demand for natural gas for electricity means an increased need for flexibility. At the same time, since most of the British and Dutch fields are now mature, their pressure and productivities are declining, which reduces the scope for keeping the same production swing as before. Winter peak production is not growing, as Graph 12 shows, whereas summer production continues to grow.

Thus the cost to provide flexibility is growing in Europe, probably beyond that of the USA. The low cost of adding a few high producing wells to large young gas fields was cheap and justified the production swing in the last few years, in particular, as compared with high European storage costs, but this is not true any more.

Large import pipelines are not the answer on economics or security grounds to address this problem. Not only does the gas that is not produced and shipped during summer have an even lower discounted value than delayed domestic production because the reserves-to-production ratio is greater, but also, part of the costly infrastructure that moves the gas, either pipelines or LNG plants and ships, remains idle. In addition, security is not improved because no more gas can be shipped; in winter, these pipelines are full, and in summer, inadequate storage prevents the shipment of more gas.

**6. The Future Evolution of North America and Western (OECD) Europe**

Both North America and OECD Europe (which includes Norway, but not Russia) face a declining domestic supply of natural gas and an increase in demand for its use in the power sector. Both regions will require additional LNG imports, with certainty in North America because the Arctic prospects are remote and with strong likelihood in Europe if its largest source of foreign imports, Russia, cannot significantly increase its production and export capability. However, the two regions are facing opposite situations in terms of seasonal flexibility. The demand swing will decrease in North America, therefore requiring less flexibility, while it will increase in Western Europe, where more seasonal flexibility will be needed.




The growing lack of seasonal flexibility in OECD Europe is confirmed by the trend in the pattern of imports shown in Graph 13. Seasonal variations in imports are growing in spite of their poor economics. How will Europe respond to the still growing need for seasonality?

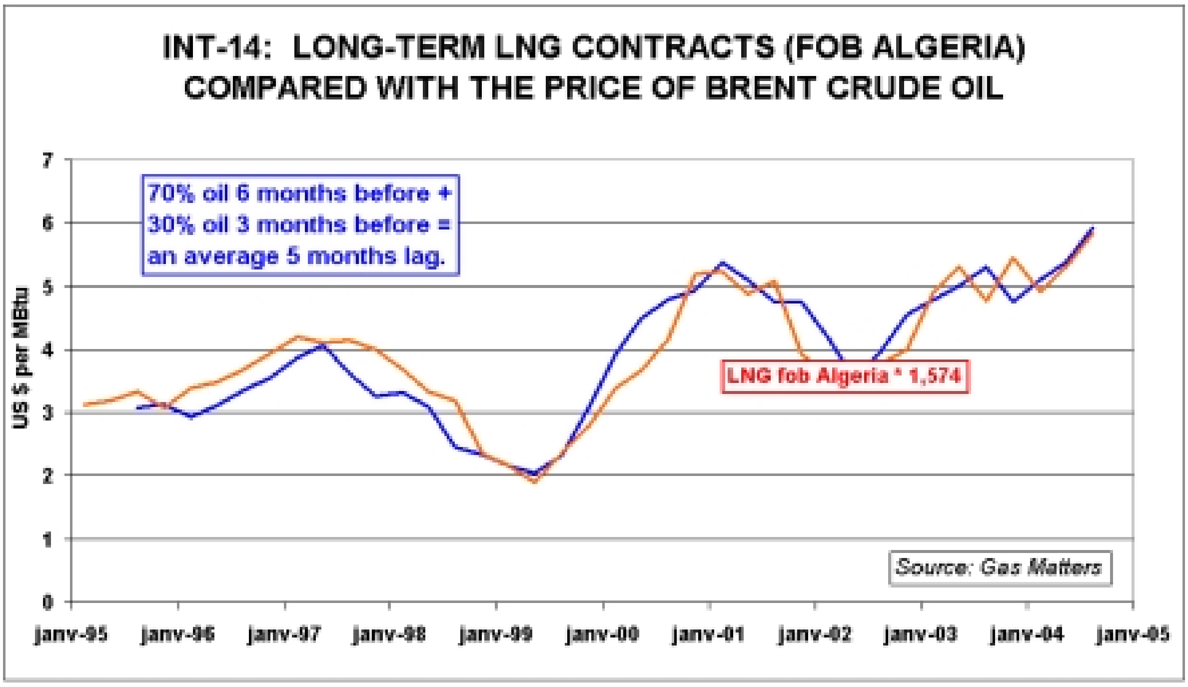
It is unlikely that pipeline exporters Russia and Algeria will accept a strong seasonal swing, but the required doubling of storage capacity is at best a remote prospect given its cost. The only other easy means to increase seasonal flexibility is to use LNG for seasonal arbitrages with North America.

LNG seasonal arbitrages between the two sides of the Atlantic Ocean or, accessorily, with Asian countries, may be triggered by physical scarcities of gas, even without perfect price signals. This was the case in 2002-2003 for Korea and Japan, when increased supply costs were absorbed by consumers who had no choice, being totally dependent on the supply and prices of their monopolies. However, without spot pricing, the scale and scope of the LNG swaps will be smaller than in a transparent spot pricing environment. This development will be further reinforced by the increasing role to be played by the USA gas market, thanks to its depth, transparency and liquidity.

Up to 2000, LNG was almost totally absent in North America because gas prices were unattractive to LNG. Domestic supply was growing regularly and was not expected to become a constraint. In addition, it was rare to re-route LNG cargoes between Europe and Asia because these two regions had their own sources of supply with long-term contracts. With the now tighter domestic gas supply in North America, one may wonder whether Europe will not have to propose attractive and transparent prices to gas suppliers to be competitive in its own right. This overall trend coincides with the market reforms launched by the European Commission and the need for flexibility of the European LNG “islands” (Iberian peninsula, Turkey, possibly Greece).

More generally, the pressure of competition, either between different regional markets or within a given regional market, may be expected to introduce more flexible pricing. This is what is happening in Asia, which has turned from a buyer to a seller market because of the growing regional, if not international, demand for its relatively plentiful gas. The recent deals signed by China with Australia and Indonesia are a clear downwards departure from the “old” Japanese-dominated price system based on the parity between LNG CIF and a basket of regional sweet paraffinic crudes.

This basket, called the Japanese Crude Cocktail (JCC), was chosen because of quality reasons due to the environmental constraints and because the protection of the Japanese refining industry by customs duties made it cheaper than to import heavy fuel oil. As these two constraints played a lesser role in Europe, the gas monopolies chose netback pricing mostly based on a weighted average of the price of substituted petroleum products (generally about 50% heating oil corresponding to residential/commercial uses and about 50% heavy fuel oil corresponding to industrial uses).




These formulae were used on twenty-year contracts with severe take-or-pay clauses, i.e., base load supply without seasonal dimension. This is shown in Graph 14 based on actual recorded prices. It shows that the Algerian LNG price is well modelled by an oil indexation with a five-month lag.

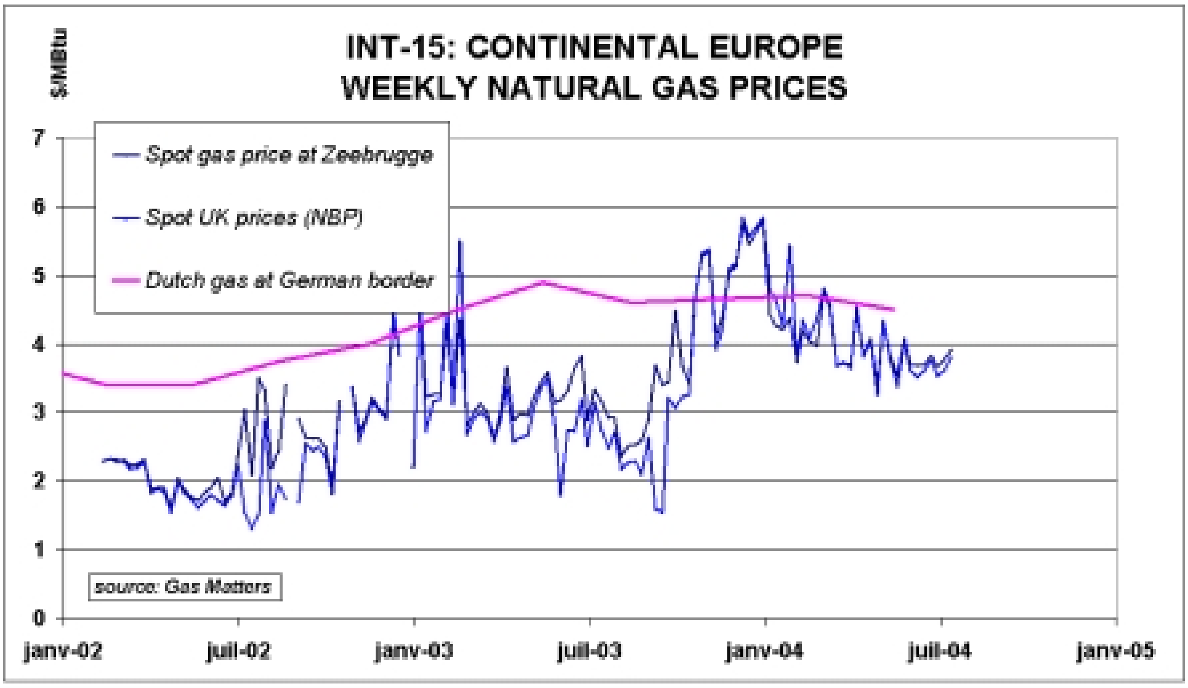
However, this kind of pricing has several handicaps:

- It reflects an average and not a marginal competition, whereas the right competitive price signal is one which reflects the instantaneous supply/demand balance at the margin;
- By only depending on the price of oil or oil products, it does not reflect the spot value of gas, high in winter and depressed in summer because of the swing in demand in key markets;
- As it was combined with “destination clauses”, it makes the re-routing of LNG cargoes where gas shortages exist difficult it not impossible.

**7. What Is at Stake for the European Gas Market Reforms?**

There is no doubt that market reforms are needed, because a competitive market will bring relevant signals and allow the flexibility of geographical swaps, but the transition from the former pricing context is difficult because reforms are rarely a win-win situation for all stakeholders. In this regard, it is interesting to compare what happened in the USA during the 1980s and what might happen in Europe.

In the USA, the situation was frozen because the pipeline companies (which were both transporters and merchant companies) had committed new supply at high prices and were confronted with a fall in demand. The deal offered to them by the Federal Energy Regulatory Commission (FERC) was to free themselves from these buying commitments but simultaneously, to allow third party access and eliminate their merchant function. Lower prices had a positive impact on demand and progressively allowed producers and transporters to regain market share. At the same time, the development of pipeline-to-pipeline competition brought the costs of transportation down, compensating partly for the fall of final natural gas prices.




In Europe today, the situation is different than the USA of the 1980s because there is neither a demand crisis nor stranded gas. However, as shown in Graph 15, there is a clear difference in terms of average annual gas prices between the lower but more seasonal spot prices in the UK and Zeebrugge (Belgium) and the smoothed prices associated with long term take-or-pay contracts, for instance, the Dutch gas delivered to the German border.

So, who is going to lose?

- Generally speaking, it will NOT be the gas companies if they can renegotiate their former contracts on the basis of the new current spot prices (there are contract re-openers anticipating such changes in most contracts) or are paid the difference between actual and negotiated prices as stranded costs;
- Possibly the transport companies (who are presently confused with the gas monopolies) COULD stand to lose if the cost of access and/or the allowed returns of the unbundled networks are lowered;
- Certainly, however, the domestic producers and the exporters[2] to Europe WOULD lose if wholesale prices are reduced by competition more than the transportation costs within Europe.

[2] For the producers and exporters, the strategy to seek downstream rents will probably not materialise. Industrial consumers who are not truly interruptible against HFO will be reluctant to accept higher prices and lose the subsidies enjoyed at the time of the monopolies. Electricity is a high-value outlet but will not generate rents because of increasing electricity-gas convergence. Lastly, the fact that the local distribution companies have not become "eligible" customers means that they cannot contract directly for new supplies (the more so when they have signed long term contracts with their holding companies). The only road left is long and expensive: the picking of customers one by one thanks to retail competition.

## 8. Energy Market Reforms and the Evolution of LNG

Whether and how distribution and retail supply companies should have access to the wholesale market or to direct long-term contracts is discussed in the body of this report, but the question of LNG swaps is of relevance to the fundamentals of electricity and natural gas pricing. In this regard, one has to remember the importance of infrastructure (liquefaction plants, LNG ships and LNG receiving terminals) and of the lead-times to site and build them, a minimum of five years given the length of the regulatory and decision making process. In other words, much of the new market cannot and will not exist before 2007.

| **Orders of magnitude in the three OECD regions by end 2000 (rounded figures)** | | | |
|---|---|---|---|
| | **North America** | **Europe** | **Asia-Pacific** |
| **Electricity** | | | |
| Total public utility and non-utility capacity (GW) | 944 | 682 | 365 |
| Annual electricity production (TWh/year) | 4800 | 3400 | 1840 |
| Expected annual growth (TWh/year) | 120 | 70 | 50 |
| Corresponding annual growth in Mtoe/year [3] | 18 | 11 | 7 |
| **Natural gas** | | | |
| Annual consumption (Mtoe/year) | 715 | 415 | 120 |
| Unmet swing for final uses (Mtoe/year) [4] | - | 18-27 | ??? |
| Expected annual growth for electricity (Mtoe/y) | 15-18 | 4-8 | 5-7 |
| Expected annual growth of LNG for electricity (Mt/y) | 12-15 | 3-5 | 4-6 |

It is clear from the above table that the potential for swaps is significant with, for instance, the excess summer European gas traded with North America and Japan. However, three conditions must be fulfilled:

- A large enough LNG trade. That will be the case in about five years, given the many liquefaction plants that are due to come on stream and the enormous Qatar and Iran potentials;
- Excess shipping and import terminals capacities (this is likely for the shipping, with 50% capacity growth, but uncertain for terminals because of NIMBY[5] attitudes);
- Full wholesale spot markets, and prices allowing arbitrages and hedging (wholesale markets exist in the USA, Canada, and the UK, but their emergence is uncertain in Europe and unlikely in Japan).

Swaps have a cost of about $1/Mbtu, which reflects the availability of the next LNG re-gasification terminal (20-30 cents per MBtu) and of extra shipping capacity to cross the ocean (60-80 cents per MBtu). Such a cost needs to be compared with the value of the swap, i.e., the seasonal difference between the prices in winter and summer in Europe. Such seasonal values are not available, but one may estimate them. For instance, the shadow differential reflected in the flexibility clauses of the former British Gas contracts when it was the only buyer of all British fields was a discount greater than 50% for summer gas as compared to winter gas, or about $2/MBtu today, a value consistent with the economics of delayed production. As it is much greater than the $1/MBtu indicative cost,

[3] If it were assumed that all additional electricity demand was fuelled by gas with an average efficiency of 50% (heat rate of 6800 Btu/kWh). North American gas demand for electricity would have risen by only 15 Mtoe per year between 1999 and 2001, but this may be attributed to the lower economic growth of that period. European gas demand would have grown by about 5 Mtoe/year more than the indicated figure because there is still room for increasing the capacity factor of coal and nuclear plants.

[4] This figure is uncertain but is expected to increase quickly with the growing maturity of the British and Dutch gas fields. As compared to the flat European winter production, summer gas production has increased by more than 20 billion cubic meters/year since 1996. The growth of demand could push this figure up by 50% by 2007.

[5] Not In My Back Yard

there is no doubt that large amounts of gas will be seasonally swapped between the two markets on either side of the Atlantic Ocean.

In the LNG world before 1999-2000, spot arbitrages were rare (spot cargoes resulted from a better than planned output of the LNG chains). The LNG "market" was dominated by vertical integration, similar to what existed in the oil market prior to the first oil shock. The period from1999-2000 was a period of comparable importance to 1973-74 in the oil market. Not only did the oil price rise to $22-28/barrel make LNG economical (if priced against heavy fuel oil) in all regions of the world, but also the fall of the USA supply called for new LNG imports, therefore opening the deep, transparent and flexible USA gas market to the rest of the world. As for oil, where the full impact of the end of vertical links was only fully felt in the early 1980s because of the long lead times for new investments, LNG is poised to lose at least part of its vertical integrated long-term contracts and become dominated by spot pricing. Energy market reforms are closely linked to this upheaval. At the very time when gas is undergoing this fundamental change, its rapid growth in the electricity sector is the trigger for a new convergence that calls for an acceleration of the pace of market reforms.

**9. Electricity and Natural Gas Convergence**

The concept of convergence summarises the theoretical potential for an electricity and gas provider to choose whatever is more economic at any point of time, either to sell its gas directly or to sell it as electricity after using it in a power plant[6]. The instrument to make the choice is the "spark-spread", a word much inspired from the oil refining "crack-spread", when the choice is to either use the feedstock directly or to transform it into more sophisticated petroleum products in a fluid catalytic converter (FCC).

Basically, this concept implies that a choice can be made to maximise the economic rewards. In fact, based on the previous analysis, one may wonder whether "convergence" is not happening spontaneously and very rapidly in the market, thus killing the opportunities of arbitrage between the electricity and gas markets. To answer this question, one must remember three facts:

- There is a gas demand in the electricity sector because CCGT is the cheapest full-cost option[7] for base load use if one uses high discount rates (justified by the uncertainties created by reforms) that "kill" all the capital-intensive projects (such as hydro, nuclear and coal);
- At the margin, the price of gas is set by its petroleum competitor in the electricity sector rather than in the industry that works in base load. This process says that, price-wise, it makes no difference whether gas or its petroleum competitor is used because they have the same value;
- Except during the gas "bubble" periods, natural gas is at parity with oil products. Being the most expensive fuels, oil products are used "at the margin", i.e., for mid/peak load, at the top of the merit order ranking, and therefore set the price of electricity.

[6] This is reflected by the popular concept of spark spread. Spark spreads reflect the difference of the marginal value of gas for different conversion efficiencies at 7,000 Btu/kWh (48.7% efficiency), 8,000 Btu/kWh (42.6% efficiency), 9,000 Btu/kWh (37.9% efficiency) and 10,000 Btu/kWh (34.1% efficiency). The higher efficiencies correspond to CCGT, whereas the low values are associated with boilers or single-cycle turbines.

[7] Precise information on electricity costs can be found in the series published jointly by the IEA (International Energy Agency) and NEA (Nuclear Energy Agency), both sister organisations of the OECD, in "Reference costs of electricity". On a base load basis, and with a cost of capital of 10%, a coal-fired plant has the same full cost of electricity as a CCGT with gas at $4/MBtu. For gas prices up to $6/MBtu and lower rates of utilisation, CCGT is always the cheapest technology, even though its efficiency is lower for discontinuous uses.

The conclusion is three-fold:

- First, convergence is likely to become a fact of life rather than a strategic long-term opportunity. Should this be the case, as reasoning suggests, building CCGT is a strategy that will cover its costs but not create rents;
- Second, investors in the electrical sector willing to create long-term rents need to either lock a low gas price with a long-term contract (in which case they are not part of the spot competition any more) or to diversify in base load technologies (coal, nuclear, hydro); and,
- Third, one can foresee that "mature" reforms will result in "mature" actors willing to create long-term rents; this in turn will create the diversification of generating technologies and fuels that the "dash for gas" has pushed aside.

For the discussion of market reforms that follows, two messages need to be kept in mind:

1) Electricity and natural gas market reforms are increasingly becoming two sides of the same problem. This is true for all countries that use gas extensively; this is principally the industrialised countries because only a few developing countries have a gas market; and,
2) The challenge is not the "convergence" that actually happens as soon as competition emerges, whatever the willingness of operators, but the management of the seasonal flexibilities given the trends in the two main gas uses, that for mid/peak load for electricity and that for direct final residential and commercial use.

## PART I: EMPOWERING END-USERS

In spite of their different agendas (for instance, the solvency problem in developing countries or the desire to move to retail competition in the developed countries), most countries see the benefits of energy market reform. Such reforms are not an end in themselves, and their long-term benefits in terms of security of supply, quality of service and efficient systems (not to mention lower prices, which are not always the result of reforms) need to be understood and accepted by the electorate.

A country's desire to launch reforms is an opportunity to discover what has been tried elsewhere and to learn from the often very different choices made by different countries as well as the rewards/sanctions encountered along the paths they have chosen. Such benchmarking is not only useful because it provides new national insights - a quite useful form of transfer of technical and managerial skills - but also because of the evidence that regional integration (standardisation and interconnections) lowers the costs and enhances the reliability of energy systems.

### 1. Shifting from the Old Top-Down to a New Bottom-Up Approach

Decision-making power was for decades in the hands of single state-owned (as in most European countries) or investor-owned and state-controlled monopolies (as in the USA). For electricity, the mix of plants and fuels, the degree of reliability/security, the type and level of tariffs and even the choice of the meters were imposed on most consumers without their say so. For natural gas, the responsibility for pipelines and long-term supply contracts was bundled because it was considered the best way to expand the infrastructure. Gas distribution was controlled in a way similar to that of electricity.

Large monopolies supervised by government agencies were created after World War II. They were the preferred design in most countries because of their perceived advantages, namely:

- Lower financial costs (they could carry a higher debt level with better loan conditions and lower risk premiums because their guaranteed tariffs made them a low risk activity);
- Economies of scale and limited redundancies that were associated with the pre-war small and scattered firms, which enhanced supply security at cheaper cost; and,
- Easier, centralised decisions on investment and financing made to strike a balance between the profits returned to the industry, the taxes for government[8] and low tariffs for the end-users.

However, over time there was a growing perception of governance problems, reflected in poor management of generation (the over-building of capacities), transmission ("gold-plated investments") and distribution (overstaffing, high labour costs and cross-subsidies among different categories of customers). Beginning about twenty years ago, energy monopolies in a number of countries came under scrutiny because of these inefficiencies, the desire to favour decentralised generation (e.g., industrial combined heat and power or CHP), the breakthrough in natural gas technologies and their potential for lower scale plant and a new wind of liberalism blowing from the United States and the United Kingdom.

For USA electricity, reforms were driven by the high generating costs and excess capacity margins[9] that were contributing to high electricity prices. Reforms in the USA started with opening generation to new actors, but the main driver was the incapacity of the heavily controlled natural

[8] At the time of the CEGB monopoly in the UK, this take was about £500 million per year.

[9] New facilities were built after the first oil shock to diversify out of oil into coal and nuclear. It was a sensible decision because oil had become and remained uncompetitive for base load power generation against coal and nuclear. Too much new capacity was built because it was assumed that the rapid growth of electricity demand experienced in the 1960s would continue. Retrospectively, the only dramatic error of the former electricity monopolies was their failure in the 1980s to recognise over-building and to stop investing.

gas system to supply enough gas during the 1970s, with the result that reforms started at the well-head with the removal of price controls. In the UK, the driver was the wish to reduce the influence of the coalminers' unions on electricity prices, but a second driver soon appeared: the need to make cheap North Sea gas available to feed the growth in industrial CHP resulting from the electricity reforms.

So in both the USA and the UK, market reforms started in the upstream sector with the possibility for new actors to build their own plants (respectively, to drill new gas wells) and to provide cheaper power to the grid (via cheaper gas). In this context, high voltage (HV) transmission for electricity or high pressure (HP) transport for natural gas had to be opened with, as a corollary, the creation of competitive wholesale markets. However, distribution and retail remained largely untouched. They only came under pressure as an "extrapolation" of the opening of competitive wholesale markets.

**2. Economic Importance of Distribution Networks**

The press excerpts in the box on page 24 relate to a few specific examples about electricity market reform in the USA. They are rather negative and explain why downstream liberalisation in the USA is stalled. In Europe, on the contrary, the momentum continues. More than 80% of electricity consumers are already free to choose their supplier, and by 2007, it will be 100%. Such a contrast of experience between North America and Europe suggests that the final step in market reform, that which reaches the small end-users, is problematic and deserves more consideration that has generally been the case since market reforms started. Going too fast too far has, in some countries, added significant costs and complexity to the benefit third parties and private shareholders, but at the expense of the end-users.

In certain cases, in particular for many developing countries, full market reforms extending to the retail competition might be unsuitable because they are too expensive to design and apply and too complex to encourage competitive outcomes. There has been bad experience with privatisation to new owners and in price trends for end-users, which explains why the pendulum is swinging back in favour of more oversight and less "freedom" for private actors. Recent political moves on this matter have included the introduction of heavier regulation and step-in powers.

This move backwards is not a denial of the benefits of market reform and competition, but it raises a number of questions that address, *inter alia*, the downstream sector. Why was this sector often overlooked in the early stages of reforms for reasons which had nothing to do with its possible inefficiencies (in the same way that reforms have been misguided when they have assumed that market power and over-investment were solely the result of "monopolies")? Is it because the opposition to change of those who want to retain their entrenched benefits, namely the trade unions, has been more successful in distribution than in generation?

Most countries have concentrated reforms on generation and wholesale trade. However, some have improved their distribution efficiency, and some, not always the same countries by the way, have already introduced retail competition, thus showing that the downstream sector may also be addressed in terms of reforms. As Graph I-1 shows, distribution costs represent on average 30-40% of the total costs of electricity supply, but for domestic and small commercial customers, this can exceed 50%. The question of whether it is preferable to start market reforms upstream (generation for electricity, with or without a wholesale market and wholesale competition for natural gas) or downstream (at the distribution level) should be answered in the context of the greatest and earliest benefits that can be achieved, and not because upstream represents a greater share of the total costs of electricity supply.

In the past, reforms often started upstream because of the significant generation costs, because it was feasible and economic to introduce competition in this sector and because such reforms were believed to be simpler, easier and therefore quicker to achieve. In the USA, distribution was not a problem because of the strong tradition of regulation by the PUCs (public utility commissions), whereas the over-investment in generation capacity, the impossibility to move to CHP and distributed energy in the electricity sector and the gas shortages of the 1970s were good reasons to push upstream reforms. In the UK, reforms initially kept the distribution as it was - privatised CEGB and British Gas (BG) - and introduced competition in the upstream sector to correct the inefficiencies there. In other countries, notably Australia, some reforms were initiated by the privatisation of distribution.

**Downstream deregulation: A few recent snapshots in the USA press**

December 2001: The US CAEM (Center for the Advancement of Energy Markets), a think tank that advocates the deregulation of energy markets, predicted that

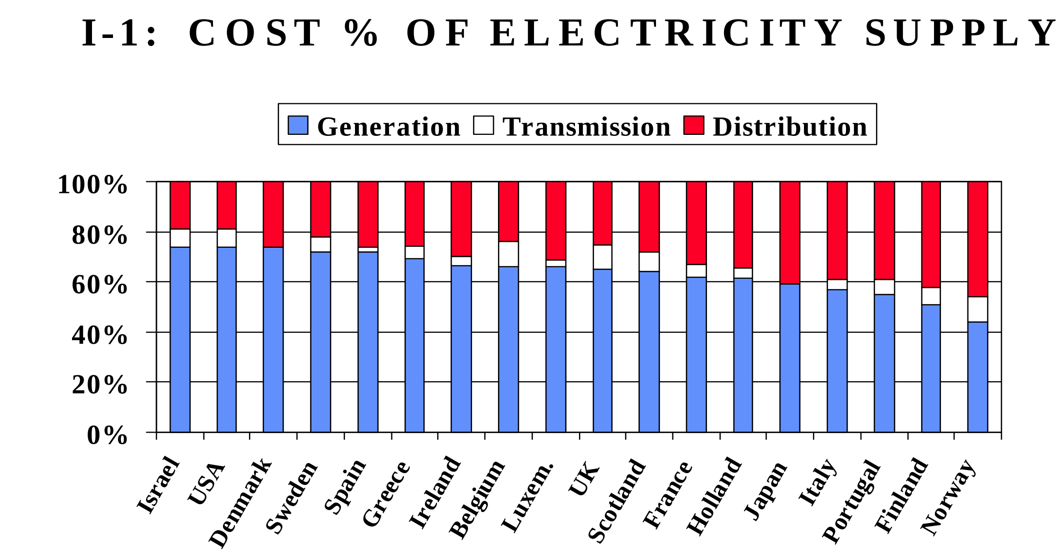
- "the movement toward retail energy competition would continue, albeit much more slowly,
- Texas was the best model to date and would set the standard for other states in 2002 and beyond because this model tied changes of the wholesale market to the retail market with no price caps, limited market power of incumbents, and enlightened leadership.
- Actually, beyond Texas, the best hope for significant movement toward competition in North America lied in Canadian provinces, particularly Alberta and Ontario. This would slowly work its way here given the increasing interconnection between the US and Canada."

June 10, 2002: "Almost half a year after its much-ballyhooed launch, electric deregulation in Texas remains an unfulfilled promise. Rates, which dropped January 1st when deregulation took effect, are rising again [showing that CAEM is wrong: there is market power]. Most consumers have been slow to switch from their long-time monopoly utility to a new electricity provider, while thousands of others have encountered billing problems. Electricity trading has been tarred by disclosures of "sham trades," and barely 4 percent of Texas' 5.5 million eligible meters have been switched from an investor-owned utility to one of several new electricity marketers. Despite those small numbers, the task of accounting for customer switches has proved to be too much for the computer systems of the utilities, the providers and the electricity reliability council of Texas (ERCOT)."

July 2, 2002: "In 1997, Georgia stood at the pinnacle of the trend to deregulate energy markets. In moving too quickly, however, it upset a stable market place. Rates have fluctuated. Consumers have become confused. And many of the natural-gas marketers that provide the fuel source have exited the scene. Markets have reflected that. Five years ago there were 19 marketers and today only 8 of which 4 control 94% of the market. Of course, consolidation is part of the free-market process and could be considered healthy. But, the fear is that market power will eventually concentrate in too few hands, leading prices to rise. Should such a result occur, the concept of deregulation could suffer a death knell. For some, that means markets there are ripe for growth and competition is still valid. For others, it is a more ominous signal that natural-gas deregulation is on its last leg in Georgia. Lots of customers just want a return to normality, and to buy from a company they trust. In the words of the chairman and CEO of AGL Resources, Georgia's experiment is "inherently unstable" and must be revised "again and again" if it is to work."

August 15, 2002: "Interest in Texas' new competitive electric market reached a new milestone recently when the Texas Electric Choice web site, www.powertochoose.org logged its one-millionth visitor after its creation on February 1, 2001. The web site was created by Texas Electric Choice, a public education campaign launched by the Public Utility Commission of Texas to inform Texans of their right to choose the company that provides electricity to their home or business. On January 1st 2002, a new state law gave most Texans the right to choose their retail electric provider on what matters most to them**,** whether it's price, customer service, or renewable energy. More than 330 000 [6%] customers have switched electric providers since the market opened."

March 5, 2003: "You would be hard pressed to say consumers are better off today after the restructuring of the electric markets. We made a lot of mistakes," said Ken Malloy, CEO of the CAEM [see top of the page] "It was intellectually dishonest to assume deregulation would cut power prices, but that's how it was sold to the public. Very few energy services companies are competing to offer electricity to homeowners because they cannot compete with the still-regulated, low rates offered by the utilities. It remains to be seen whether (deregulation) will ever be worth a dime for homeowners. We're still years away from having energy services companies that provide the total energy needs for the home - light, heat and air conditioning - at a set price, like some energy supply companies (ESCO) are now providing to their corporate clients."



*Source: IEA (after John Paffenbarger)*

Today, there are good reasons to consider that distribution should be a priority for market reform:

- The successful cost reductions in distribution, for instance, in Australia, Portugal or the UK;
- The deeply-rooted inefficiencies that may exist when strong trade unions control the public distribution networks (over-staffing and golden status systems);
- The excessive number of distribution companies in some countries (for example, 900 in Germany, 700 in Italy) that may prevent economies of scale; and,
- The potential to achieve economies of scope.

This is even truer in developing countries, where both distribution and retail supply are often distorted (e.g. tariffs not reflecting the costs, cross-subsidies, non-technical losses). Even though retail competition is often regarded as complex and risky, reforms need to address both distribution and supply tariffs[10]. Looking at the supply side alone can be a recipe for failure, as the Brazilian electricity reform experience shows.

### 3. The Main Features of Distribution

The schematic presentation in Graph I-2 shows a standard looped network with the three links of electricity (respectively gas), upstream (power plants for electricity, fields or remote imports for gas), midstream (high voltage or high pressure transmission) and downstream (large users buying directly from the transmission grid and local distribution companies). Distribution includes all customers not directly fed by the main grid (small residential customers and medium-size customers, such as large commercial users or small industries), whatever their arrangements for supply (serviced as captive customers or by other suppliers if there is retail competition).

A rule of thumb is that each category of customer (small, medium, large) represents more or less the same order of magnitude in terms of overall energy consumption, but the numbers of consumers in each category are differentiated by a factor of 100: the number of large consumers is ~0.01% of the total, that of medium consumers ~1%, and that of households nearly 100% of the total number of

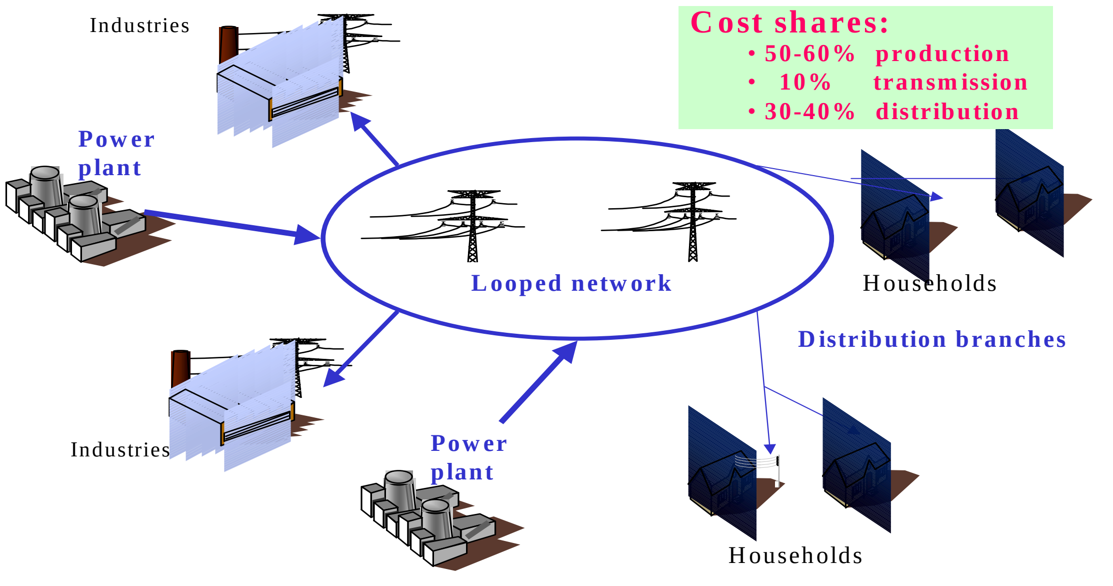
[10] Thus, a comprehensive reform agenda for the downstream sector of developing countries may include the lowering of distribution costs and the reduction of non-technical losses that will partly compensate for the higher energy costs because of the introduction of cost-reflective tariffs (without cross-subsidies).

customers. The following table shows some actual figures for two countries (one developed, the Netherlands, and the other developing, Algeria) both of which have mature electricity and gas grids; it uses the UK electricity situation as a kind of benchmark. “Medium” consumers are important because experience has shown that they have the most to gain from retail competition; this is because large customers always have strong bargaining power while small consumers often have little leverage in contractual terms.

| ENERGY/COUNTRY | Number of customers per category | | |
|---|---|---|---|
| | large | medium | small |
| Electricity/Algeria | 64 | 33000 | 4.9 millions |
| Electricity/Netherlands | 650 | 59000 | 7.0 millions |
| Electricity/UK | 6000 | 60000 | 26 millions |
| Natural gas/Algeria | 24 | 180 | 3.0 millions |
| Natural gas/Netherlands | 200 | 1900 | 5.7 millions |

These figures are not strictly comparable because of definition changes: a large customer is defined as one who consumes more than 1 MW in the UK while it is more than 2 MW in the Netherlands. However, both have the same 0.1 MW threshold for small customers. What needs to be kept in mind is that the total energy consumption in each of the three categories is of a similar order of magnitude (i.e., around one third of the overall consumption for each category).

**I-2: THE LINKS OF AN ELECTRICITY SYSTEM**



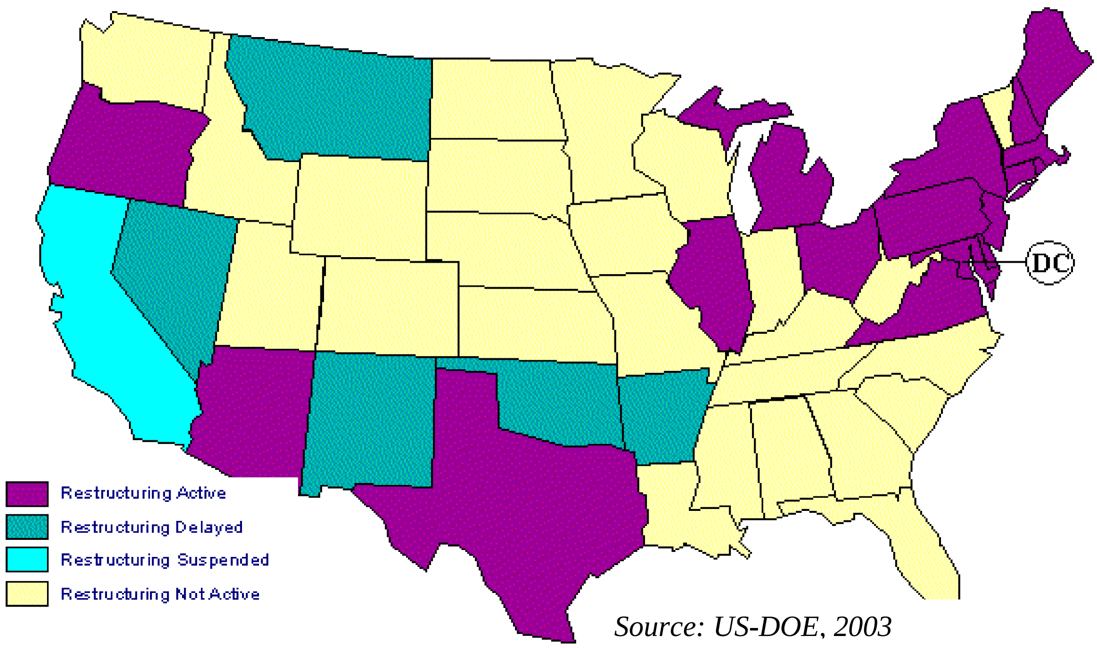

*Source: EDF, Jean-Paul Bouttes*

### 4. What Is Happening in the US and the European Union?

Because the number of small customers in an energy market is so high (usually in the millions), retail competition is complex, and the sophisticated data requirements for suppliers to serve them are significant. This explains why market reform in distribution has often been problematic and subject to errors which have led to cost increases. The countries that have gone the furthest in market reform in distribution have been developed countries with stable and low growth, mostly North America, some parts of Western European and Eastern Australia. With few exceptions (e.g., the Nordic market), there has been a lack of interest by householders in switching suppliers for relatively small price reductions. The same lack of interest applies to switching insurance or mortgages, even though this would normally achieve higher savings than changing one's electricity or gas supplier.

In the USA, as shown in the following map, some states have concluded that the savings from retail competition are insufficient to cover the implementation costs. Only a few states have launched retail competition (also known as "retail wheeling"). The states with active restructuring are those with the highest average state tariffs. High tariffs may be unrelated to reforms and have specific regional causes, for instance, the hurdles for energy investment in California or the Northeast, or such tariffs may have been a driver of the choice to go to retail competition. Whatever the reasons that these states have engaged in retail competition, one should note that in several cases, e.g., Arizona, Illinois, Michigan and Pennsylvania, their electricity tariffs are now higher than those of their neighbours who did not engage in active restructuring. Oregon is an exception because, thanks to hydro, its electricity prices are among the lowest in the US.

**I-3: RETAIL COMPETITION IN THE US**




*Source: US-DOE, 2003*

In the European Union, the view is that legislation related to the unbundling of transmission, distribution and supply is essential to prevent cross-subsidies that would be detrimental to competition in the future liberalised environment. Hence, electricity and gas transmission/distribution system operators (TSO/DSO) are required to be independent, in terms of their legal form, organisation and decision-making, from activities not relating to transmission and distribution. A compromise enables the member states to postpone the implementation of provisions on the unbundling of DSO until 1 July 2007. However, DSOs with 100,000 customers or fewer are exempted from unbundling provisions.

In most developed countries, energy market reforms have been undertaken in different stages. Often, a first stage has been to introduce competition in generation and wholesale supply. Retail competition is either introduced/planned in a second stage (the case in all countries of the European Union and in a few states in North America) or has been dropped in other North American states. But no common approach exists for distribution reforms. In North America, where a strong regulation tradition exists, it is an ongoing effort. In the European Union, it was part of the initial reform process in some countries (Portugal and UK), or it now takes place with the opening of retail competition in countries like Spain (for implementation in 2005) with a new "revenue cap" scheme (based on the accounting information provided by the companies), or it does not appear to be envisaged at all, e.g., in France.

Overall, regarding distribution and retail supply, partial experience and information exist here and there and may be used to discuss the many relevant issues that a country or market might face:

- How can the efficiency of distribution companies (reduction of labour force, better cost balance between manpower and IT) be improved? Through yardstick regulation, through privatisation or via franchises?
- What kind of new structures for the distribution companies are desirable: through privatisation, size and scope, by creating independent companies or subsidiaries of larger regional companies?
- Should a proxy of competition be introduced in the distribution sector via franchise bidding?
- Should competition be introduced in retail supply via unbundling and customer choice?
- What kind of "consultative committees" of energy consumers should be created to have a say in the regulatory decision-making process or in the management of their LDC?

The table on the following page summarises some of these questions in the third EC benchmarking for the 15/25 national markets.

## 5. An Agenda for Developing Countries: Economic Sustainability of Tariffs

Even developing countries which believe that the lack of capacity margin and the launching of new cheaper plants should have priority over the downstream sector are aware that their financing problems are caused by the perceived risks associated with the distribution and retail sectors of electricity and gas markets, e.g., tariffs to deliver energy that do not reflect the actual costs, consumers not paying their bills or the recovery of foreign-funded investment in local currency. Much of this "country risk factor" is related to the downstream sector and calls for transparency and accountability because no sustainable electricity or natural gas system can exist unless prices are fully cost reflective (in the sense there are no permanent subsidies) and are paid.

India confirms that distribution is at the core of energy market reforms: "*Distribution sector is the key to the reforms process in the power sector. It poses the greatest challenge to the reform process as it has maximum complexity in terms of being the segment of the business in direct contact with end-users, and in that the fundamentals of other segments i.e., generation and transmission, are derived from this segment. One of the aims of the distribution reforms is the empowerment of the end-users and that their grievances are promptly handled. In the Indian context, empowerment does not necessarily mean retail choice to consumers. What consumers really want is adequate and reliable quality power at reasonable/affordable price. This is one of the biggest challenges before the distribution system.*"

For India, the counterpart of a service of quality is the economic sustainability of the downstream: "*Distribution reforms take prominence because of the quantum of distribution losses which requires increased efficiency more than anything else. In some regions of the country, distribution losses amount to nearly 60%. A structured reform process is called for to limit these losses. On the whole, the key points on the Indian reforms process are: Reducing cross subsidies, strengthening distribution systems, including measures for prevention of theft and pilferages, separation of supply from distribution in the organization structure*". By putting these principles into action, India appears to have solved loss problems in some areas. Their methods of metering and accounting should become a case study for other countries.

| | Declared market opening (%) | Unbundling: transmission system operator\owner | Unbundling: Distribution system operator[4] | Regulator | Balancing conditions favourable to entry | Biggest generators' share of capacity (%)[5] | Biggest 3 generators' share of capacity (%)[6] |
|---|---|---|---|---|---|---|---|
| **Austria** | 100 | Legal | Accounts | ex-ante | favourable | 6[7] | 33 |
| **Belgium** | 80 | Legal | Legal | ex-ante | unfavourable | 59 | 66 |
| **Denmark** | 100 | Legal | Legal | ex-ante | favourable | 0 | 25 |
| **Finland** | 100 | Ownership | Accounts | ex-post | favourable | 11 | 29 |
| **France** | 37 | Management | Accounts | ex-ante | moderate | 78 | 86 |
| **Germany** | 100 | Legal | Accounts | planned | unfavourable | 23 | 61 |
| **Greece** | 34 | Legal\Mgmt | Accounts | ex-ante | unfavourable | 85 | 87 |
| **Ireland** | 56 | Legal\Mgmt | Management | ex-ante | moderate | 80 | 90 |
| **Italy** | 66 | Own\Legal | Legal | ex-ante | moderate | 43 | 72 |
| **Lux** | 57 | Accounts | Accounts | ex-ante | unfavourable | 0 | 0 |
| **Neth** | 63 | Ownership | Legal | ex-ante | favourable | n.k | 33 |
| **Portugal** | 45 | Ownership | Management | ex-ante | moderate | 59 | 74 |
| **Spain** | 100 | Ownership | Legal | ex-ante | favourable | 37 | 79 |
| **Sweden** | 100 | Ownership | Legal | ex-post | favourable | 16 | 50 |
| **UK** | 100 | Ownership | Legal | ex-ante | favourable | 16 | 37 |
| **Norway** | 100 | Ownership | Accounts | ex-ante | favourable | 12 | 24 |
| **Estonia** | 10 | Accounts | Accounts | ex-ante | unfavourable | 15 | 21 |
| **Latvia** | 11 | Legal | Legal | ex-ante | n.k. | 0 | 0 |
| **Lithuania** | 17 | Legal | Legal | ex-ante | moderate | 0 | 29 |
| **Poland** | 51 | Management | Accounts | ex-ante | moderate | 4 | 25 |
| **Czech R** | 30 | Legal | Accounts | ex-ante | unfavourable | 43 | 53 |
| **Slovakia** | 41 | Legal | Legal | ex-ante | moderate | 29 | 40 |
| **Hungary** | 30 | Accounts | Accounts | n.k. | moderate | 5 | 41 |
| **Slovenia** | 64 | Legal | Accounts | ex-ante | unfavourable | 16 | 43 |
| **Cyprus** | 0 | Management | None | ex-ante | not decided | 100 | 100 |
| **Malta** | 0 | Derogation | None | n.k. | not decided | 100 | 100 |

A sustainable demand (in the sense of an adequate customer base which can afford to pay and does pay the tariff) is a top priority of the energy market reform agenda in developing countries. This was revealed by the development of the independent power producers (IPP). They were very successful in bringing new electricity supplies to industrial "niche" markets. Demand was solvent, power purchase agreements were honoured and fuel supply agreements were tailored to the specific needs and constraints. However, when the IPP concept was extended to the provision of additional supply to the national grid prior to reforming distribution, the principal risk was that the supplier would not be paid, a situation that occurred in some Asian countries, e.g., Pakistan and Indonesia, precisely because final demand for electricity was not solvent.

In other words, subsidised electricity prices for too many captive customers are not sustainable. Lack of government money cannot be replaced by inflows of private capital[11], and subsidies designed to protect and favour the poor often work against them because the subsidies are captured by other income categories. The fact that solvent (usually industrial) markets provide the goods, whereas insolvent (residential/commercial in developing countries) markets do not is the first issue to address in market reforms with three facts, as listed on the following page.

[11] As mentioned by Turkey "*It may for example be observed that without taking the aggregate losses and costs in distribution network under control, no country could be successful in the creation of an energy market that will attract the private sector/investors to invest in this energy sector without demanding extra and creditworthy guarantees from Treasury*".

- How to reduce distribution costs that represent a large share of the costs for captive users;
- How to ensure that tariffs reflect costs and are paid, in particular in developing countries;
- How to ensure that the reformed local distribution companies (LDCs) are sustainable in the long-term.

Thus an initial aim of market reforms should be to lower downstream costs, get rid of cross-subsidies (generally higher tariffs for industries than for households in developing countries, the opposite in developed countries), reduce direct subsidies to a sustainable level (e.g. for the agricultural sector or for the poorest of the poor) and to set a design that is sustainable in the long run as Argentina did but Brazil did not. These aspects are closely related and suggest that one should reform the bundled distribution-retail service before envisaging the possible unbundling of distribution and competitive retail supply.

Concentrating on the downstream sector does not mean that reforms in the upstream sector should be delayed. Final tariffs also reflect the cost of supply, and as shown by the UK example, there is often room in developing countries to reduce generation costs for electricity supply. In fact, because of poor logistics and narrow national preferences, fuel costs are often higher than they need to be. Reforming the gas sector, pooling the logistics at the regional level and putting competitive pressure on the national coal industry (where one exists) should also be considered in the reform agenda.

**6. Privatisation and Source of Funding**

Distribution is a natural monopoly. “Empowerment” does not mean that it is possible to get rid of this constraint, but it does mean that reforms should allow end-users to have their say in choosing their supplier so they can achieve cost and price reductions. Often the private, as opposed to public, ownership of distribution is debated as an essential step in reducing costs and providing for customer choice. In previous work, such as *Energy for Tomorrow’s World—Acting Now!*, WEC has argued that the privatisation question depends on the circumstances of a market, the performance of the company as a commercial entity, its true market power (in a national or regional context) and the country’s need for hard cash. For WEC, privatisation is not the number one priority of energy market reform, and it is open to question whether private utilities, with or without real market power, can be expected to perform a public service or whether a public monopoly can be allowed by the state shareholder to operate in a totally commercial setting.

The privatisation of the distribution companies in places like the UK or Latin America (see the 2001 WEC study *Energy Markets in Transition: The Latin American and Caribbean Experience*) shows the positive results of such an effort, whether the country is developed or developing, although the experience in Argentina and Brazil shows that there are wider difficulties also: the social cost of laid-off employees (which was not anticipated and taken care of in advance in these two countries) and the reliance on foreign funds rather than domestic savings to finance new infrastructure.

The French water market is a case in point. Water distribution was a state monopoly up to the $19^{th}$ century, when it was then opened to private capital as a “delegation of public service”, with the possibility for the often over-staffed and over-paid municipally owned water companies to be transformed into private franchises. This opening was a success; the share of privately-managed water companies in France has continued to increase, even recently during the tenure of French Socialist governments. Given the fact that there were only three bidders (VEOLIA, SUEZ and SAUR groups) for the awarded temporary water franchises, one might have feared market power and local political influence. While problems in this area did occur, they did not lead to a come-back of municipally owned monopolies.

One of the keys to the success of the French private sector in water supply and management was strong and reliable French capital markets. French investors in the water sector avoided the costs and currency uncertainties of heavy foreign capital borrowings. In contrast, it is surprising to see that most of the energy privatisation process in developing countries has been financed by foreign capital. There is no doubt that foreign capital is expensive and that, if domestic capital had been available at lower cost, it ought to have been preferred. It is the financing or funding issue which reveals that energy market reforms are only a sub-set of a much broader reform agenda.

The main problem of the developing or transition economies in energy market reform is not the lack of savings or financial expertise, but the inadequacy of their institutional framework and property rights. Developing countries generally enjoy high saving rates, sufficient to finance their infrastructure in the same way as developed countries did during the 19$^{th}$ century. But domestic capital faces more hurdles for investment in the country than foreign capital does, with the result that these savings are not invested in energy infrastructure and remain "potential". This is the most critical and important problem of "reforms".

In a similar way, the availability of new techniques and management methods is not a constraint and has never been a bottleneck to sustainable development. The problem is to integrate technology in the social and industrial fabric of the country, a challenge related to the institutional framework and its necessary evolution in lockstep with economic development. The institutional framework has three major components:

- Legal environment: property rights, gender equality, rule of law;
- Social environment: education, health, social justice, equitable social infrastructure;
- Physical environment: sustainable food, energy, water, telecommunications and transport infrastructures.

Institutional conditions are of a cumulative nature with the stock of legal, social, physical and other "assets" driving the capacity of a country to incorporate sophisticated technology. In developed countries, this accumulation of know-how and institutional support took 150 years (from 1800 to WWII), during which purchasing power grew by about 1-1.5% per annum. This may look slow, but over 150 years, it increased purchasing powers 4-8 times, leading developed countries to where they stand today. Developing countries have the same, or even greater, potential of "catching up" if they establish the right institutions, in particular, broad property rights and the legal framework that goes with them. This was achieved in Asia with much of the infrastructure financing being provided by domestic capital. Growth rates reached double digits. Conversely, if these basic institutional reforms are not put in place, it is very likely that energy market reforms will stall.

In the case of energy distribution, the freeing of domestic capital for privatisation purposes has two facets: on the one hand it is a monopoly, i.e., an activity with low risk so it can easily attract domestic capital in the long run as long as true ownership or control is possible as was the case in the USA market; on the other hand, the initial reform phase may be plagued by the perceived uncertainty and risk that go with any change, especially in developing countries. In either case, domestic investors may be reluctant to make energy infrastructure investments unless public money from the country's public purse is also involved. Public money, however scarce, could still be the only cheap capital available, because, even with favourable conditions, foreign private capital can be very expensive, in particular because of the currency risk.

However, in the broad perspective, before looking at where the money comes from, one has to examine how it will be used and whether the returns are attractive. This leads to a three-fold agenda for privatisation:

- Better appraisal of the breakdown of costs for the distribution companies: How are the costs split between running costs (reading of the meters, invoicing and follow-up), maintenance (lines and meters) and new investment? What are the manpower costs in the different tasks, and can they be reduced or outsourced?

- Revenues of the distribution companies: What are the technical and non-technical losses? Are tariffs properly set, or do subsidies distort the price signals? How do tariffs reflect the peak and growth of demand? What part of the revenues comes from other sources (stranded costs or public “electrification or gasification” funds)?
- Sources of finance for privatisation: What is the cost of capital in the country, and how deep are domestic financial markets? Can domestic investors invest, and on what conditions will they do so? In the event it seems impossible to tap domestic savings, what are the barriers, and what is the alternative cost of foreign capital?

## 7. Why the Move from State-Owned to Investor-Owned Distribution Companies? [12]

The long record of public-owned energy distribution companies has been excellent but has turned sour in recent times in many countries because of improper governance. Governance has five aspects: integrity, quality of service, leadership/management, costs of capital and costs of manpower.

*Integrity:* The German civil service at the time of Bismarck was an example of integrity and efficiency, possibly because Bismarck knew all civil servants personally and was able to draw the best from them and maintain high ethical standards. Similar success stories exist in many fields and countries, for instance, the mail distribution, education, utilities, etc., and may still be true today in some countries or parts of countries. Reciprocally, civil servants were proud to belong to the public service and were convinced that their job was highly “ethical”, falling into the realm of “public interest”.

This tight link between the civil servants and “their” public has loosened. With urbanisation, people become anonymous and the face-to-face relationship that was the basis of the ethical behaviour of civil servant has progressively waned, except maybe in the countryside and small villages where people know their postman, the teacher of their children, the income tax officer, etc. That may explain why Norway, for example, is still happy with its small public municipal LDCs. However, even in Norway, the phenomenon of urbanisation and the potential for economies of scale will force the municipalities to sell their energy distribution services to create larger companies.

*Quality of service*: Experience shows that utilities excel at restoring service in the worst conditions, whether they are publicly-owned or in private hands. The ownership argument does not explain the tradition of restoring service, often with the help of reserve linemen (retired or culled from the ranks of other utilities), a practice which exists in all utilities throughout the world whatever their ownership.

*Leadership/management:* Governance is also related to the interface between the top management and the political leaders. As long as the management of utilities and the long-term investment decisions were straightforward (based on economies of scale) and political decisions by governments were implemented by long-serving, non-political civil servants, ownership was not a constraint and was even (or still is, for instance in some developing countries) an advantage. However, with the disappearance of economies of scale and a more rapid turnover of high-ranking civil servants who play an increasingly short-term political role, the benefits of effective public ownership have largely disappeared.

*Capital costs*: The issue is discussed in a January 2003 Standard & Poor’s paper: “…*if investor-owned utilities are unable to persuade their regulators to allow them to raise rates to accommodate for external factors, then it is the shareholders who take the hit. In some cases, such as PG&E, the lack of cost recovery has led the company into bankruptcy. By contrast, municipal utilities are typically financed by debt and therefore, it is the bondholders who bear the risk. Yet, those note*

[12] There are countries, such as Mexico or Turkey, in which the state constitution prevents the privatisation of certain essential sectors. This was justified when such laws were promulgated but needs to be re-examined periodically to adapt to new circumstances.

*holders are normally willing to issue debt to cities under favourable rates because electric municipals are self-regulating. That means a city can readily modify its rate structure to maintain its costs, minimizing the risk of a municipal utility falling into financial disarray. The consequence is that their cost of capital is about 25 percent less than their corporate counterparts, largely because they can issue tax-free debt. Because of that, the interest rate offered on such debt can be 2 to 4 percent lower than corporate bonds. Their bond ratings reflect those realities…*"

Indeed, the cost of capital is highly dependent on the perceived risks: capital with a state guarantee is cheap, at least as long as the state is creditworthy and can borrow under its own guarantee (not necessarily the case today because the funding capacity of many states, particularly in developing countries, has reached a limit). However, as shown by the USA investor-owned utilities (IOU), a monopoly like distribution can also find cheap private capital providing that investors are confident in the regulatory stability.

Manpower costs. Ownership did not make much difference in the early days, precisely because of the direct control associated with the face-to-face relationship described above, but with the growth of utilities, trade unions have gained in strength. Guaranteed employment contracts and civil servant status give a strong leverage to employees of state-owned utilities and often prevent cost reductions as quickly as would be the case in a private company. Even though the UK[13] is an extreme example as compared to, say, ESKOM in South Africa, there is an unavoidable trend towards higher costs as state monopolies grow in size.

The example of the French or Argentinean water companies [14] as well as the recent choices regarding natural gas or electricity distribution in developing countries like India and Mexico[15] favour private distribution. In Mexico, natural gas distribution and retail supply are carried out by the private sector with exclusive concessions granted for twelve years. These examples also support the argument that it is easier to rely on the private sector from the outset because one then avoids the entrenchment of the former public incumbents when they feel threatened by private ownership and discipline.

### 8. Bringing Costs Down: Yardstick Regulation and Competitive Franchising

Competition through privatisation is generally a driver of efficiency because competition will force private investors to enhance the management, bring new technologies and use the available possibilities of economies of scale and scope. However, it will achieve little if it is not combined with efficient regulation[16]. Yardstick competition is often used but is not easy to implement. Incentive-based regulation may also be difficult to apply, for instance, to choose the "X" factor of

[13] At the time of the CEGB monopoly in the UK, there were 1,000 employees per coal-fired unit as compared to 200 today; it was impossible to start or stop such a plant in less than half a day (it takes 30 minutes or less today) or to change the coal quality (today, the cheapest supply is always sought).

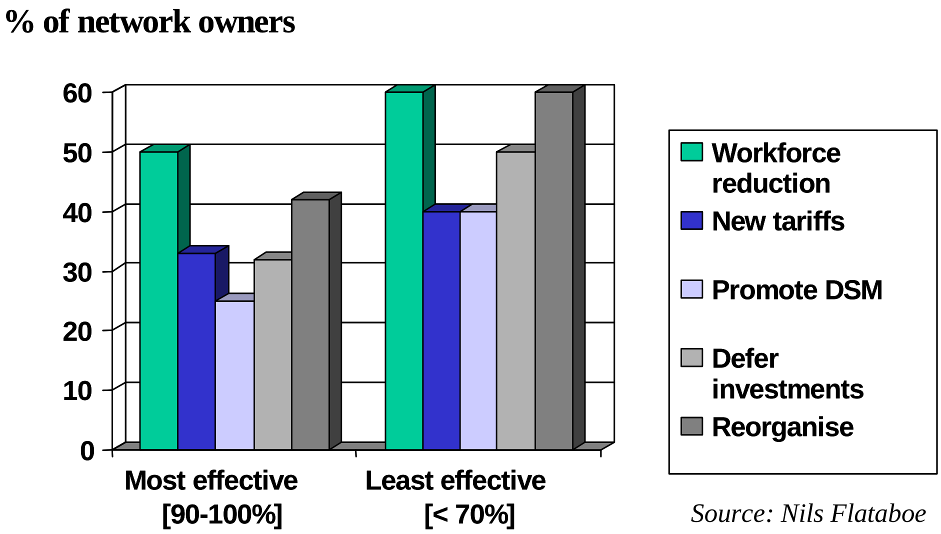
[14] *The Economist* provides the example of Argentina, where privatisation brought increases in productivity and profitability. "The largest privatisation involved the transfer to Aguas Argentinas, a consortium led by Lyonnaise des Eaux, a French company, of OSN, a federally owned entity in Buenos Aires. At the end of the first year, prices for both water use and connection were lower than they had been at the start. Non-payment of bills had been high; by cutting customers off after three unpaid bills, the company got 90% of its customers to pay. The number of employees was cut by almost half. In its second year, Aguas Argentinas was highly profitable. From $25 million a year in the decade before privatisation, the company's investment rose to about $200 million a year in 1993-2000. Connections to the water and sewerage networks rose, especially among poorer households. Other water privatisations in the country seem to have achieved broadly similar results. Overall, childhood mortality fell by 8% in areas where water services were privatised, and by 24% in the poorest areas..."

[15] It should be noted that in the early 1990s, there were basically no gas distribution networks (except one in the city of Monterrey and two other minor cities). At present, thanks to the opening in 1995 to private players, there are 20 cities where a network already exists or is under construction; there are already 25,000 kilometres of distribution pipeline, and the number of contracts that the distributors have signed is close to one million with a volume of sales over 280 Mcf/d.

[16] Whether competition should also include the franchising of local distribution companies for limited durations was a question welcomed by some members of the study group (in general, the countries where distribution is still a public monopoly) but dismissed by others as an unproven concept. Those in favour argue that franchises allow the benchmarking against peers, i.e., a kind of "competition".

an "RPI – X" formula (where RPI measures the inflation of the relevant costs and X the added annual efficiency gain, because of the dissymmetry of information [17] between the regulator and the incumbent companies.

**I-4: COST REDUCTIONS IN NORWAY IN THE MOST AND LEAST EFFECTIVE LDC**




*Source: Nils Flataboe*

In Norway, LDCs are municipality-owned and managed. Graph I-4 shows that, whatever the initial effectiveness of these LDCs, the largest cost reductions resulted from workforce reductions and reorganisation. These reductions were driven by a strong yardstick regulation and the implicit benchmarking which goes with it. Would privatisation have led to higher efficiency, as it has done in France? The answer would be affirmative if the higher capital costs faced by private companies played a lesser role than the better management that might be expected from investor-owned entities.

Cost reductions (e.g., in Norway or Portugal) are neither easy to achieve nor rapid without benchmarking. In the case of the UK, small cost reductions[18] were achieved until 1996 because the "RPI-X" regulation formula used the same low "X" values, around 2-4% (adding to the 3-4% of the RPI at the time) for the twelve regional electricity companies as for the gas grid.

Another difficulty of yardstick regulation is the "Damocles sword" that hangs over the LDC because of regulatory uncertainty and risk. There is a dissymmetry of information, and the regulator may be unaware for a while of the "excessive" benefits enjoyed by the LDC. If the regulator notices that the LDC is making high profits, he may change the rules, the "X" factor in the case of the UK, and unilaterally modify the return prospects of distribution. Such regulatory action, which could entail higher discount rates, less reliance on debt and higher costs for consumers, is harmful enough in itself but would have even more serious effects in developing countries relying on foreign capital because it could lead to all investors leaving the country.

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[17] There is no proof that private franchises reveal, through the value of the bids made to acquire them, the performance that bidders expect. However, neither can one say that a system of franchises is as opaque as a single distribution monopoly or very large LDC.

[18] Again, some members of the study group do not agree there is any evidence that competitive franchises achieve more and faster cost reductions. In this regard, the possible splitting of UK TRANSCO, the country-wide gas network, into smaller entities, will be interesting in terms of whether such a move will lead to cost reductions.

The auction of franchises may help to avoid drastic regulatory changes by revealing the cost reductions that the downstream sector can achieve. Such private distribution franchises may be established for periods of, say, 10-15 years (long enough to allow a fair return on the efficiency gains and investments and create a setting favourable to long-term supply contracts). They may be an effective means to tap private capital and management expertise and ultimately, to better use human resources, invest in new technologies and rely on outsourcing for specific tasks.

However, the actual evidence available so far on private distribution franchises is mixed. The example of Brazil is a failure because of a flawed design. The problem was not a deficiency in the privatisation of the distribution system itself (even though the social treatment of the redundant manpower was badly handled) but the fact that the authorised supply tariffs were not consistent with the wholesale prices. The UK railways is another example of failure because the private companies did not invest as they were supposed to. In contrast to this experience, the success of water franchises in both developed and developing countries, as well as the experience with Mexican gas concessions indicates the potential of franchises.

## I-5: DECREASING MANPOWER

| Country | Form of Liberalisation | Annual decrease in employment | Time Period |
|---|---|---|---|
| Victoria, Australia | privatisation, competition | 10% | 1989-96 |
| Hungary | privatisation | 4% | 1995-97 |
| New Zealand | corporatisation | 10% | 1987-92 |
| United Kingdom | | | |
| National Power | privatisation, competition | 13% | 1990-95 |
| PowerGen | | 10% | 1990-95 |
| British Energy | | †8% | 1996-98 |
| United States | impending competition | ‡3% | 1990-96 |

Note: † projected by company. ‡ major investor-owned utilities

*Source: IEA, John Paffenbarger*

The only statistics on cost reductions are aggregated values for electricity, but Graph I-5 shows that the potential for manpower savings is significant and confirms that if the same recipes – privatisation, competition, and independent regulation - were systematically used for the most labour-intensive distribution sector, the benefits would be considerable.

It is certainly worth investigating whether and how the competitive franchise model may be implemented. Difficulties are not inconsiderable because privatisation and competition go against the entrenched interests of the former public monopolies and because some bad past experiences (in Brazil or the UK, for example) show the importance of the design. For instance, if the ownership of the franchised networks remains in municipal hands, the incentive to invest may decline progressively and disappear at the end of the franchise period unless this has been anticipated in franchise contracts to cover who makes decisions for investment, how capital costs are recovered and what the last recourse in case of conflict is. In addition, as long as distribution and retail supply remain bundled, distribution restructuring cannot take place without supply tariffs restructuring.

## 9. Optimal Size of Local Distribution Companies[19]

As discussed earlier in the description of an electricity or gas network, three different categories of customers were identified: large, medium and small. For the sake of simplicity, let us assume that the 0.01% of very large customers directly connected to the high voltage or high pressure transmission grid are not part of the distribution system. In this case, the distribution network would be the grids (wires or pipes) that supply all the medium or small customers.

There is no such boundary in the UK gas market, where TRANSCO manages the totality of the grid, but elsewhere in general, there is a split between the large customers connected to the main grid (say >100 kV in the case of electricity) who use their substantial bargaining power to manage their own supply de facto, even faced with a monopoly, and the medium (small industrial and large commercial) and small (residential and small commercial) customers who are supplied through a separate distribution network.

In the distribution sector, when it comes to medium or small-sized customers, it is difficult to separate their requirements, which are interwoven and served by the same set of sub-stations. In other words, if one wanted to identify and gather only the small customers, one would end up with groups of a few hundreds users, much too small to be worth a separate distribution entity. This is precisely the issue at stake in retail supply; small users may be less interested in shopping on their own, while medium users may have such an interest.

UK experts suggest that economies of scale are achievable up to 5-7 million customers. However, their view may be influenced by the initial structure of the energy industry before reforms[20]. In addition, given that there are at maximum a few tens of millions of customers in most countries or states, the “ideal” market of a 5-7 million customers would not allow more than a few distribution companies to achieve profitability, each one with its own regional characteristics which would be difficult to compare and benchmark. Offsetting the UK viewpoint on the optimal size of a distribution market is the experience of Portugal, which restructured its four established distribution companies into a single company with 5-6 million customers with no evidence of economies of scale, according to domestic studies and foreign consultants.

Other experts suggest an optimal size LDC with a customer base up to 100 times less, consistent with the 900 German LDCs, the 700 Italian LDCs or the 305 in Ontario (where the smallest ones are the most cost-effective). There are even examples of smaller distribution companies in Norway, where each city has its own municipal company. In the Netherlands, after mergers, the average-size LDC has a few hundred thousand accounts. Unless a distribution market starts with one monopolist for the whole country, the question of optimal company size to maximise economies of scale will find its solution thanks to market forces. The same can be said about economies of scope, because distribution often involves the same kind of civil engineering for gas-water-sewage-steam pipes or electricity-telephone-TV cables and may be cheaper to handle in a single municipal entity.

In the evolution of industry structure, the regulator has a key role to play. He should be with the legislator at the heart of the initial design of the distribution network, with the objective to find the best trade-off between the economies of scale/scope and the accountability and performance benchmarking of the distribution companies which take part. In this process, customers should have their say, in particular, with a preference in favour of smaller, more responsive LDCS which know and serve the neighbourhood. “Small locally and large globally” may be a good concept, as long as it respects the specific regional circumstances.

[19] The study group is not in agreement on this section because of the lack of strong empirical evidence. Thus, this section is meant to stimulate further debate.
[20] In fact, natural gas distribution has always been provided by a single private monopoly. Transco and electricity distribution was in the hands of twelve regional companies.

There is no consensus on what "local" should mean in terms of size for an LDC. It depends on whether the population is dispersed or not, whether the LDCs in the market are multi-service or not and whether they have responsibility for retail supply or not. The ideal market could range between a minimum[21] of a few tens of thousands to a maximum[22] of a few million customers, with an average around a few hundred thousand energy accounts.

**10. Optimal Size of the Retail Supply Companies**

In retail competition, supply is unbundled and obeys its own dynamics of economies of scale and scope. One commentator has said "*There is no doubt that economies of scope will be a touchstone for all companies involved in retail competition. The principle of core competence will play a role here as also the convergence in the industry. If the companies view themselves as service providers, then they become single point of contact for customers and transform themselves into multi-utility firms*".

In addition, as shown by the successful[23] example of CENTRICA, now a well-known brand name in the UK and elsewhere, branding can play an important role in the economies of scale and scope at the retail level. One might generalise that part of the distribution & retail success in the energy sector in the future will be the recognition and value of brands. That does not necessarily call for larger LDCs in terms of delivery, but at least for large holding companies.

Retail supply, if it is to be competitive, has to fulfil a few obvious principles:

- Competition cannot exist without a minimum numbers of competitors, say 4-5 at least;
- Supply companies with large and diversified portfolios of consumers enjoy economies of scale; and,
- Supply is regional by nature and depends on the demography (population density and lifestyles) and topography (islands, mountains, or plains).

**11. Meeting Contradictory Goals: Small Locally and Large Regionally**

To be small locally and large regionally or globally, a distribution company might be part of a large holding companies or rely on outsourcing, or a combination of both. Large national companies already exist in Europe or in many developing countries. They have started to become regional actors and bring financial and technical capabilities that smaller players may not enjoy. The problem that faces regulators is to keep them as large entities but spread them geographically to allow the emergence of local competition.

Outsourcing may also be a component of a multi-utility/service strategy (see next box). For instance, RWE has expanded in four key areas [24] (electricity, gas, water and waste-management) as it seeks to bundle these services under the slogan "one group, multi-utilities". This strategy fits well with the German context of the municipal LDC ("Stadtwerke"), for which RWE provides outsourced services and expertise.

[21] This is a size that certainly enables consumers to have a strong grip on the workings of their LDC, benchmark their LDC against neighbouring LDCs, ensure competition for the franchises, and achieve the benefits of economies of scope (with the blessing of the regulator and competition authorities). The uncertainty is whether economies of scale will be missed because of this small size.

[22] This is a size that certainly permits economies of scale without having to rely on outsourcing or larger holding companies, but such a size may be too large for efficient competitive franchising, supervision and benchmarking.

[23] The CENTRICA success story raises the question of how far not to diversify. It is not easy to blend different corporate cultures, and the mixing of energy services with the workings of the British Automobile Association, now owned and operated by CENTRICA, may be too challenging. Synergies may exist in the management of large volumes of customers, remote workforces, spare parts, data, sales and marketing but, as shown by the recent problems of VIVENDI, telecoms and plumbing services have little in common.

[24] Water has become one of the RWE core businesses since its acquisition of Thames Water, bought as part of a drive to expand abroad to diversify its business portfolio after the liberalisation of the power market in Germany in April 1998.

Thinking along a similar line, if economies of scope had been an important driver of efficiency in the UK (they only are to a limited extent today), one would assume that the competition authorities would have demanded to reduce the size of LDCs operating in the UK market.

**12. Unbundling**

The starting point of energy market reforms is the separation of transmission and upstream activities. The aim is to put power generation for electricity, production and long-distance imports for natural gas on a competitive footing while transmission remains a monopoly (public or private, depending on the circumstances). With competitive supplies of electricity and gas "unbundled" from transmission, a competitive wholesale market can be created. Some countries stop there and keep energy market reform simple and focussed, while others have gone further by partly or totally separating distribution and retail supply (retail competition).

To determine whether to go further in unbundling distribution and retail supply, there are three practical questions must be answered:

- *The nature of the separation:* Is it limited to accounts (the two activities remain in the same company but with separate accounts), or does it reach a legal level (the two activities are in different legal structures), perhaps involving different ownership (different legal structures and ownership)?
- *The extent of the separation*: Does it include wholesale supply that frees the large customers directly connected to the transmission grid, or retail supply that frees some (medium) or all (medium and small) customers connected to the distribution grids?
- *The pace at which separation proceeds*: Are the customers connected to the distribution grids unbundled all at once or progressively, with the possibility of stopping the process of retail competition if the costs and risks overtake the benefits?

The unfortunate experience of the USA in retail unbundling is partly a problem of design but possibly also a question of pace and extent. The EU experience is that of a phased opening together with the decision to go to full retail competition by 2007. To what extent is this experience relevant in other regions?

During the WEC South Asia workshop on market reforms in February 2003, it was argued that, given the hassle versus the benefit, small customers would only switch their supplier if a 10% price reduction were proposed. One might compare this order of magnitude with two different figures:

- *Actual retail margins:* They are about 2.5-5% in Australia, according to the August 2002 review of the effectiveness of FRC for electricity by the Australia Services Commission, too small to be reduced, especially if distribution is already tightly regulated; and,
- *Actual costs paid by the households*: The table on page 40 shows that energy spending in the UK has been halved between 1968 and 1998. A 10% reduction would today represent 0.3% of the spending, too low to justify much hassle, especially if the regulator does his job of squeezing distribution costs to a minimum.

**Outsourcing: Inner Strengths and Limitations ***

If utilities want superior services at competitive costs, they need to consider outsourcing. It is a direct result of deregulation and the need to be more competitive, forcing companies to plough their resources into their core operations and to delegate other duties to third parties to improve cash flow, customer satisfaction and earnings per share. All aspects of utilities' operations are open to outsourcing, which include everything from tree trimming to billing to customer care. So, utilities are cutting out their excesses and focusing on their strengths. If a process can be done better and cheaper by others without sacrificing customer service, then it is a candidate to be outsourced.

For instance, vertically integrated utilities may have several departments involved in the permitting, construction and delivery of all the infrastructure required for new residential development with an often disparate and uncoordinated process, but competitive pressures are pushing utilities to streamline the procedure. Instead of a clumsy effort, some utilities have created a single process where one manager can complete the project from beginning to end. EXELON Infrastructure Services in Philadelphia says that it can oversee not just the infrastructure management of electric and gas systems but also telecom and cable systems, and by doing so decrease costs per customer from $4,000 to $2,000. Similarly, CONVERGYS, another outsourcing firm based in Cincinnati that specializes in billing and customer care solutions for the telecom industry, says that it can improve utilities' processes and beat their current costs by between 25 and 50 percent.

Because of the uncertainty of deregulation, outsourcing has stagnated. But the continued pressures to cut costs, boost operational efficiencies and improve customer service mean that an increasing number of utilities will rely on outsourcing. A recent survey of 480 IT managers from all types of companies says that 73% of those questioned are currently dependent on outsourcing while 36 percent said they intend to outsource their IT functions. Further, a SCIENTECH 2002 report found that the two most favourable groups for outsourcing are investor-owned utilities and co-ops. "Utilities are catching up with other industries and learning that you can get world-class customer care and billing solutions without infrastructure investment and with minimal risk," said Jamie Biddle, CEO of ORCOM. Montana Power, now North-Western, for example, has turned over its billing-statement system to ORCOM because it would have taken years and a huge investment of capital to develop the necessary software.

While outsourcing can cut costs, utilities must remain committed to providing first-rate services, or suffer the wrath of customers and regulators. Moreover, full-time workers employed by the utility can accumulate significant know-how over time, which is often worth the extra cost. Labour unions are hammering the point that a diminished staff correlates with a reduction in quality of services, and places utilities at risk. "Our contractors are giving us quality work, but they won't be around if the system breaks down," says Dave Claussen, maintenance superintendent for Western Resources.

Yet when properly managed, outsourcing non-core functions can create higher-quality service at lower cost. If current systems are inadequate, utilities must decide if they want to invest in them or outsource certain services to others who have a proven expertise. Executives will be less fearful of giving up control once they see the effect on the bottom line and customer service. Utilities striving to grow their revenues and to increase their sales must implement cutting-edge technology solutions. If they wait too long, they run the risk of being acquired by more efficient companies. That's why one can expect that utilities will increasingly turn to outsourcing ancillary services to third parties.

*July 9, 2002 – Analysis drawn from a paper prepared by Ken Silverstein, Director, Energy Industry Analysis, after the Utility Limited press release announcing that Customer-Works, a professional outsourcing firm for customer management services, is now going live with 500,000 new customers for British Columbia Gas. The company already serves 3.5 million electric and gas customers from such utilities as ENBRIDGE (Consumers Gas & Services) and CENTRICA.

| UK AVERAGE HOUSEHOLD WEEKLY SPENDING | | | | |
|---|---|---|---|---|
| | **1998** | | **1968** | |
| | **£ per week (1998 prices)** | **% of total expenditure** | **£ per week (1998 prices)** | **% of total expenditure** |
| Leisure | 59.8 | 17 | 21.1 | 9 |
| Food & non-alcoholic drinks | 58.9 | 17 | 63.9 | 26 |
| Housing | 57.2 | 16 | 30.7 | 13 |
| Motoring | 51.7 | 15 | 25.4 | 10 |
| Household goods & services | 48.6 | 14 | 28.8 | 12 |
| Clothing & footwear | 21.7 | 6 | 21.5 | 9 |
| Alcoholic drinks | 14.0 | 4 | 9.9 | 4 |
| Personal goods & services | 13.3 | 4 | 6.2 | 3 |
| Fuel & power | 11.7 | 3 | 15.0 | 6 |
| Fares & other travel costs | 8.3 | 2 | 6.3 | 3 |
| Tobacco | 5.8 | 2 | 12.6 | 5 |
| Miscellaneous | 1.2 | 0 | 0.7 | 0 |
| **Total expenditure** | **352.2** | | **242.3** | |

This relatively unattractive cost/benefit balance is not a compelling argument against retail competition, especially if one believes that it is important to clearly separate competitive and regulated activities. As noted above, if the unbundling of retail supply is considered, it should be about when and to what degree to proceed, i.e., what timely and prudent step-by-step approach allows suppliers to demonstrate whether it feasible to go further and customers to show more interest over time in the opportunity to choose one's supplier of electricity or natural gas. The assumption that the freedom to choose will be taken up and sustained by busy retail consumers is not supported by the evidence, but this does not mean that the regulatory principle of retail unbundling should not be pursued on market power, industrial organisation or other grounds.

Some developed countries have engaged in retail competition because of large individual consumption (e.g., in the Nordic countries, which pioneered such reforms) and/or different supply and distribution load profiling (thus justifying their separate treatment), but the main driver is the fear of cross-subsidies between the competitive (supply) and regulated (grid) sectors.

In the developed countries that have not yet engaged in this level of unbundling, the large customers already access the transmission grid directly and have strong bargaining power. Retail competition may then be offered to the largest captive "medium" customers (small industries or large commercial users who had no bargaining power with the former monopolies even though their large consumption left room for better commercial contracts). A further stage would be to keep the same threshold of consumption, above which full retail competition is possible, and extend it to groups of smaller customers who aggregate their demand to qualify. Then in subsequent stages, the threshold could be progressively lowered to allow new categories of smaller users to become eligible to choose their retail supplier. In this way, even for the smallest consumers who would remain captive to one supplier, distribution costs would be invoiced as such and not confounded with the costs of supply.

In the early stages of reforms of developing countries, especially in the poor countries where demand for electricity is growing fast, the first objective of reforms is to ensure that new supply comes on stream soon enough to meet the demand. While wholesale competition and the regionalisation of energy markets is a critical part of this challenge, retail competition is complex, costly and risky. It would seem logical to keep reforms simple and focussed on upstream unbundling while delaying retail unbundling until the energy system has reached a minimum degree of maturity. This level of maturity includes having enough private companies at the national or regional level to ensure real competition, a situation which is often not the case in developing countries, at least until they achieve a level of economic progress which is linked to a high degree of access to affordable, commercial energy services.

More generally, the question is to identify what the business risk is. If it is the launching of new plants, the best regime may be to limit competition to the tendering of new plants. If the business risk is related to the workings of the downstream sector, one has to examine whether distribution and retail supply should be unbundled. If they are unbundled, they become two separate businesses, each one bearing its own risks, and their cooperation must be formally established. If they remain bundled, there is no split of responsibility, and the risks remain mixed.

The European Union believes that keeping distribution and retail supply bundled obscures the risks. Not only does it eliminate competition in retail supply and the customer benefits which would result, but keeping the distribution and retail supply bundled also allows cross-subsidies between distribution and supply and between different categories of customers. This risk is significant, at least for medium-size customers, as evidenced by the high rate of switching which occurs when unbundling has been established. However, whether it is also true for small customers remains unclear because it depends on whether their load profiles for the use of distribution and generation/transmission (that controls the supply) are similar. Some believe that these profiles are so similar that they do not justify retail competition, while others believe the opposite.

The best WEC can say, at this stage, is that when energy markets mature, competition needs to be broadened first to wholesale and then, progressively, to retail, initially for the largest captive customers and possibly for the smaller ones as well.

**13. Summary of Part I: Empowering End-Users**

The essence of market reforms is to replace the former top-down decision-making process with a bottom-up approach based on empowering end-users who want to have a say in the price and quality of their energy services, either directly for the largest consumers, or through their LDC for the smallest consumers, providing their LDC remains under their close control. Distribution should be *a*, and sometimes *the*, priority of reforms. It is a major source of inefficiency, and in most developing countries, the *sine qua non* condition for success.

While there is no consensus in WEC on all the elements of reform related to energy end-use, and while one size does not fit all countries, it is possible to summarise four steps to reform in the downstream sector which should be addressed, one way or the other, by government energy policy and stable, clear, investor-friendly regulations based upon it:

*Privatisation of the management and labour force*: In the past, WEC has not put a high priority on privatisation in the context of energy market reform. However, the analysis of the evolution of state-owned utilities over time shows that, sooner or later, governance and financing problems arise and call for institutional changes. Even if the ownership of the electricity or gas networks in a country remain in public hands and operate in a commercial context, privatisation of state-owned utilities can improve the governance, bring new technologies and know-how and avoid the costs associated with the “public servant” status of the workforce. A key ingredient of success in energy market reform is to reduce the political and regulatory uncertainty because uncertainty has a cost in the form of increased risk; privatisation can help achieve this.

As one member of the WEC study group has said, “A monopoly is the most primitive form to generate or distribute a product or a service. At an early stage, and under specific conditions of the environment, it may be justified (e.g., the reconstruction of the energy infrastructure in Europe after World War II or the initial infrastructure development in developing countries). Yet if the concept of sustainability has not only a physical sense of natural resource and environmental conservation, but also a social (accessibility of commercial energies to all human beings) and economic sense (economic efficiency), the development of society will inevitably lead to their extinction in the long run as more efficient methods of production and distribution have evolved".

Of course, privatisation is also driven by the need for cash to expand energy infrastructure and services, especially in markets where accessibility is a problem. In some developing countries this is an urgent matter but one that should only be addressed in the broader context of reforms which could unleash domestic savings to offset the need for foreign capital.

*Making LDCs lean and mean*: This can be accomplished by an appropriate combination of efficient regulation, franchising, out-sourcing, economies of scale and scope. Franchises, if they are chosen, may extend over 10-15 years, long enough for the quality of management and service to become clear, but not so long that they lose their sense of performance and their wish to be selected at the next auction. Regarding the possibility of mergers and acquisitions in the downstream sector, it is a matter for the political and regulatory authorities, possibly with input from consumer associations, to choose from among a combination of large holding companies, reliance on outsourcing or large regional distribution companies. Given the lack of experience to date, the most desirable market is one in which there are enough competing LDCs to allow customers to compare their own LDC against those of, say, 4-5 neighbouring LDCs. In developing countries, unless a regional energy market is already established, it may not be possible to achieve this until the energy market matures.

*Phasing the introduction of retail competition*: Retail competition may require load profiling and/or new sophisticated IT systems. The smaller the customer, the higher the cost and the less attractive the cost-benefit balance. Freedom of choice already exists in the European Union for 80% of the demand, i.e., all the large customers who access transmission directly, most medium customers and some small ones who rely on retail supply. European experts believe that it is beneficial and should be promoted, at least for the developed countries, but this would not appear to be a high priority in less mature developing country markets.

*Ensuring that distribution tariffs are cost-reflective*: Private LDCs will not subsidise consumption unless they are asked to do so and are paid for it, but they might be tempted to cross-subsidise the customers who could leave the LDC (e.g., the large commercial or small industrial customers) at the expense of the smallest captive users who are unlikely to leave. It will be up to the regulator to ensure that supply cost reflects wholesale prices and the load profile, that security cost is benchmarked, and that distribution costs are consistent with the load profile and the class of consumption to which the consumer belongs.

## PART II: SECURITY OF SUPPLY, THE WIDER CHALLENGE

It has already been mentioned in Part I of this report that energy market reforms create uncertainty, especially if the scope of reforms is too ambitious with overly sophisticated models that must be modified in the course of time to reduce or eliminate unexpected and undesired results. The possible lack of long-term security is precisely the type of "undesired" which results from an excessive focus on spot competition in the early models of reform.

Changes of design create uncertainty, which in itself creates risk. This results in higher costs because the higher cost of capital (due, for example, to a larger risk premium on equity or the smaller leverage of debt) increases the costs of investments. All risks impact costs, but the worst one is the risk of regulatory uncertainty because it can have a snowball effect. The more the regulator changes the rules, the higher the perceived risk and the more reluctant the companies will be to invest, thus leading the regulator to new changes to the market design and so forth.

An example is that of price caps. When low price caps are set under the argument that, if capacity is paid for separately, price spikes are not needed anymore to remunerate reserve capacity, and that consumers should then be protected against high prices, the wrong signals are given to the generators who will try:

- To locate new plants outside areas with low caps;
- To reduce voluntarily the availability of plants with a view to maximising revenue;
- To limit investment in peaking capacity (price hikes to remunerate it are not possible);
- To interact with systems that have no capacity mechanisms;
- To keep on line economically or environmentally obsolete plants.

Unless all stakeholders are convinced that the chosen market design will provide market security without further need for regulatory intervention, uncertainty will erode confidence, increase the risk and the costs and finally prevent security from being achieved.

### 1. Can the Market Deliver Timely, Secure, Reliable and Affordable Energy Services?

Previous WEC reports, particularly *Electricity Market Creation in Asia and Pacific* (2000) and *Energy Markets in Transition: The Latin American and Caribbean Experience* (2001), addressed security of supply but did not go so far as to propose a market structure that would be responsive to the concern of security. In particular,

- The Asia-Pacific study examined the privatisation of state assets and the merits of simple reforms with long-term capacity-planning remaining under government responsibility. It warned against too sophisticated, costly and risky models based on short-term pool competition and called for cheap combinations of market features and central planning.
- The Latin America study also examined the privatisation of the upstream and midstream sectors and added that of the downstream sector (LDCs). It encouraged fair/transparent rules for the wholesale market, incentives to invest in capacity and regional integration. The creation of "indicators" to track the market was also recommended.

Access and security of supply were at the heart of these reflections, even though the concern was not expressed as such. This is not surprising because, unless specific conditions are met, short-term competition alone will not encourage the construction of new power plants, transmission lines, LNG terminals or other infrastructure early enough to match growing demand for electricity, especially in developing countries which often face added risks. Short-term price signals, hardly influenced by what is certain in the future (such as seasonality patterns), govern commodity markets. These prices are set on the short-run marginal cost, that of the last operating plant in the merit order when a capacity margin is available and that of scarcity when the margin disappears. Unless market power exists (see Part III) and leads to sufficiently higher prices to provide the economic incentive to invest beyond that which would occur under strong competition, prices will behave in a cyclical manner, sometimes being lower than the full costs (capital, operating and fuel) of a new plant, when there is idle capacity and new plant investment cannot be justified, and sometimes being much higher when there is supply scarcity and new facilities will be launched. The problem is the time lag: the long lead times to wind down old plants which are not needed or to build new plants to meet increased demand.

It is not just a question of the investment in generation to fulfil the increased demand for electricity. Investments in adequate transmission capacity, including interconnections with neighbouring markets, are also needed to allow supplies of electricity or natural gas to flow with guaranteed operational stability. These two types of investment, often involving different players and siting or other considerations, must be managed carefully. The causes of recent blackouts (mainly in industrialised countries!) appear to involve a lack of investment and/or inadequate standards, including simple circuit-breaking technology, or rules of procedure to avoid an essentially local problem cascading over large areas. Well-known operational problems become acute because competition has stretched electricity systems to their limits, and unbundling has created gaps in the responsibility chain.

Lastly, security is more than providing adequate capacity in time, i.e., launching new units early enough to be sure they will be available when new needs are confirmed. Electricity cannot be stored; when it is generated it flows. When new demands on the system manifest themselves, whether new supplies are available or not, the system operator must technically manage the network load in the most feasible way. In addition to the standard ancillary services described later, the system operator must organise the dispatch of electricity, including selective cuts if demand overruns supply in order to avoid the collapse of the entire system, such as the blackouts experienced recently in a number of countries.

In short, electricity security of supply has three components:

- *Quality and continuity of supply*: This is the “active dynamic” aspect of security driven by effective management of operations, a daunting task that one generally associates with the short-term reliability of the system. Social and political factors come into play, with the result that investment to address this type of security of supply calls for central control because it cannot be left to the market;
- *Long-term adequacy of supply:* This is the “passive” aspect of security driven by an appropriate degree of diversification and capacity margin as well as resilient transmission networks able to cope with unforeseen local disruptions. Markets will always deliver this type of security “at a price”, which may or may not be politically acceptable and perhaps not as timely;
- *Physical disruptions in supply:* This is the “perceived threat” aspect of security driven by the degree of political stability, the rule of law and regulatory certainty. The former relate to the vulnerability of primary energy supply, transmission routes and infrastructure, while the latter relate to the economic and environmental rules of the game. Markets tend to discount investments if there is too much uncertainty regarding the safety, risk or viability of the project.

**2. The Role of the Transmission System Operator (TSO)**

The active short-term quality and continuity of electricity supply involves the provision of ancillary services and the capacity to adjust to unexpected events that modify the initial planning, including the management of power/gas cuts in case of urgent need. It is a dynamic undertaking associated with network operations, under the responsibility of the independent transmission operator who can fulfil his task by using his own equipment or by buying services in the market, for instance ancillary services, such as reactive power or operating reserves for electricity. This task is hardly visible to the final consumer because it is very technical and is carried out on the fringes of the electricity system. However, it is a fundamental ingredient of the reliability of the electricity and gas systems and should not be taken for granted.

In the vertically integrated utilities of yesteryear, the appropriate mechanisms for delivering quality and continuity of service were in the hands of the central operator. In unbundled competitive systems, the short-term continuity of supply is managed by the transmission system operator (TSO) and, in the case of interconnected systems, with different TSOs (such as those in North America and the European Union). The coordination among different TSOs in a regionally integrated electricity market is of great importance, as the 2003 eastern North American and Italian blackouts have shown.

The greater the number of independent generators, e.g., with distributed energy plants such as CHP and renewables, and the greater the number of customers, the more sophisticated the short-term balancing procedures of the TSO must be. But this complexity and the costs do not affect security of supply *per se* as long as the whole responsibility chain of the electricity system is under control.

For electricity, “hot” and “cold” reserves are the most basic, if not the only, requirements to ensure reliability and quality of power supply. Availability of adequate hot spinning reserves of the order of 5% and an equal percentage of cold standby reserves are considered to be an ideal situation. It should be noted that the desired percentage of reserves is also a function of the level of reliability of the generating units, a concern that is often underscored for intermittent renewable sources or in the developing countries that are struggling for the quantity rather than the quality of power supply. [25]

Adequate and resilient transmission capacity is also required to handle the transfer of power from surplus to deficit regions and to avoid niches where ancillary services are no longer adequate. Supply mismatch is very common in all countries but affects developing more than developed countries because power generating capacities are often located near coal pit heads (for example, in China or India) or depend on hydro location (for example, in Argentina, Brazil or Venezuela), which are often remote from the high consumption areas.

The management of power reliability, i.e., short-term security of supply, implies a transparent and close coordination between the transmission system operator (TSO) and network users (generators, suppliers, traders, etc.). Operational codes need to be published because if they are not properly scrutinized and discussed with the network users, major problems may occur. This is why the regulator needs to offer incentives to all market actors, suppliers and consumers for efficient procurement of ancillary services. A solution might be to implement market-based mechanisms for the provision of ancillary services, as Spain has done.

### 3. Short-Term Price Elasticity and Demand-Side Management

Load management is an important component of system reliability and efficiency of energy markets. The California model, where wholesale prices rose without affecting end-users because they enjoyed a fixed retail tariff, should be avoided. Large (industry) and medium (large commercial or small industrial) users can manage their load, which is a choice now increasingly offered to smaller consumers as well [26]. For instance, some simple meters offer two different time

[25] In the Indian context, before planning any capacity addition to meet the increase in demand, serious thought needs to be given to the desired level of utilisation of the existing resources and to the timely input of fuel, spares, preventive maintenance, etc. in the existing power plants. This being said, the focus on “quantity” rather than on “quality” should not be a reason to neglect the necessary ancillary services (spinning reserves, redundancy in transmission capacity and transformation capacity, AVR, UFR base-load shedding and islanding schemes, black start facilities, etc). WEC’s best practises work under its Performance of Generating Plant Committee is relevant here.

[26] On the basis of large-scale deployment, capital costs for remote meters put on a fixed communications network are about $100 per home for the hardware (meter and communications module). Installation, project management, and systems integration add another $10-30 (on the basis of a large-scale deployment for hundreds of thousands of meters). However, the simplest demand response comes from pricing time-of-use and critical peak. None of these requires additional hardware, though control hardware certainly simplifies consumer response to such pricing. Time-of-use and critical peak pricing also promote investment in automated controls, thus allowing demand response to grow over time.

tariffs which allow one to disconnect temporarily dispensable appliances, such as dish/clothes washers, when price hikes are signaled by the network.

DSM (demand-side management) works well for load management, i.e., to level the load, but there is no evidence that its impact will be sustainable unless tariffs are significantly increased. This is because:

- Most consumers are insensitive to wholesale prices because the ~50% distribution component in the prices they pay is significant and the commodity is paid on the basis of pre-determined tariffs;
- Unless new equipment is introduced, most electricity uses are captive whatever the price of electricity. At best, some uses (e.g., clothes washing) will be shifted to another time of the day;
- Current household electricity budgets in developed countries are a very small proportion of overall personal spending (less than 3% in 1998/9 in the UK compared with 6% in 1968).

With appropriate metering and tariffs, DSM helps such shifts, filling the night "valleys" when the load and price of electricity are lower while flattening the daytime "peaks" of the load curve. This can even be associated with the use of decentralised supplies (distributed energy) at the time of the peaks, which is discussed later in this report.

**4. The Norwegian Approach to Short-Term Reliability**

The system operator has responsibility for the overall operation of the system and ancillary services. Supervising the overall operation of the system is a function of crucial importance to the security of supply of any power system. To fulfil these tasks, the system operator constantly monitors, adjusts or changes active and reactive production, power-flow, voltage level and network topology to achieve satisfactory power balance, operational safety (the ability to cope with contingencies) and quality (frequency, time deviation, voltage). The system operator can handle his responsibilities by controlling his own equipment as well as buying services from plant owners connected to the main grid.

| **Category** | **Characteristics** | **Compensation** |
|---|---|---|
| Frequency Response | Frequency ±0.2% (49.9/50.1 Hz)[27]<br>droop characteristic 6% | Annual economic compensation |
| Supplementary Frequency Response | Transitional arrangements 2002 with bids twice a week. The aim was to develop daily bids in 2003. | Marginal price for the last purchased MW/Hz in the actual period, paid all four months for documented delivery |
| Reactive Power[28] | Adjustment from spinning units | 25 NOK/MWh in 2002 when requested and documented |
| Frequency Activated Load Shedding | Instantaneous shedding in steps if frequency falls below 48,7 Hz | No economic compensation |
| Generating Shedding | Part of network protection scheme in order to increase available transfer capability | Compensation per disconnection:<br>Cap. < 200 MVA: NOK 50.000<br>Cap. > 200 MVA: NOK 75.000 |

[27] In India, regulations applicable to the electric power industry specify a statutory limit of + 1.5% to –3% on frequency variation from nominal frequency of 50 Hz as against the prescribed limit of ± 1% in most of the developed countries.
[28] Reactive power management plays a vital role in control of the voltage, reduction of system losses, improving the quality and reliability of power supply.

| | | |
|---|---|---|
| Power Reserves | "Option" market was introduced by the TSO in 2000/1 winter. Both producers and consumers are allowed to bid in reserves options (implies an obligation to bid into the RPM in specified periods). | The "option" price is set as the price of the last accepted offer (referred to the reserves requirement defined by the TSO e.g. 1600 MW). |
| Regulating Power Market (RPM) | A market to fine-tune the production and consumption balance with up or down regulation used when area control error and/or frequency/ time deviation exceeds specified limits in the hour of operation.<br>Requirement:<br>Volume > 25 MW<br>Response > 15 minutes | The RPM price is determined as the price of the last step of adjustment in the "up" or "down" regulation.<br>(Only one price per hour) |

In addition to these techniques, as shown in the table above, Norway has a market for secondary reserves (balancing market) consisting of a "regulating power market" (RPM) and a new "option market of power reserves". The balance between demand and consumption is planned day-to-day on an hourly basis through the physical power market ELSPOT. The purpose of the new power reserve market is to secure a satisfactory volume of power reserves in the RPM that can be called on to compensate for possible identified forecasting errors, transmission limitations in the grid and operational interruptions.

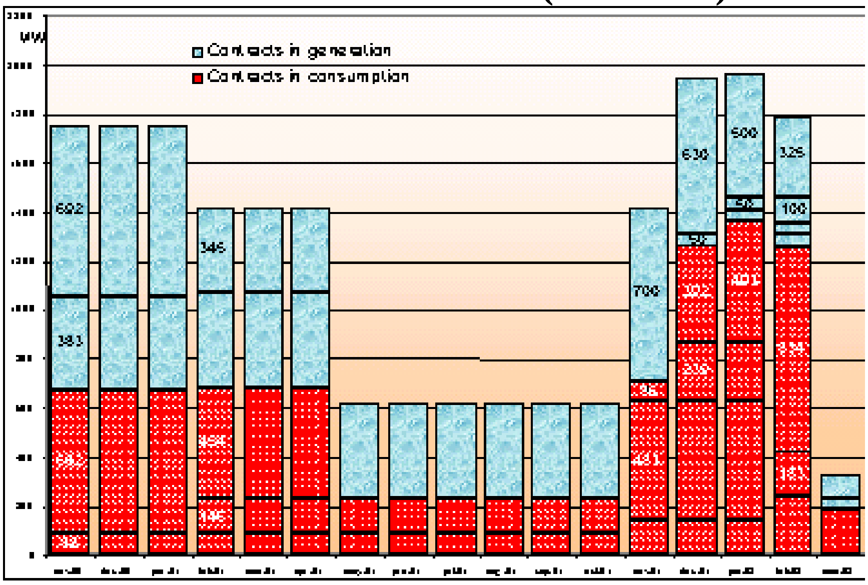
This new power reserve option scheme has enticed consumers to register with the RPM. This is of particular importance during annual peak load periods, when demand gets close to the power generation capacity limit. In the two tendering rounds so far, about 110 potential participants, generators as well as consumers, were asked to submit daytime power reserve offers, and a total of 1,745 MW of power reserves were accepted. The agreements between the TSO (STATNET) and the bidders are valid for a period of three months or one year.

Graph II-1 indicates the number of contracts, the distribution of contracts between production and consumption and the amount of power reserves offered into the Norwegian market of power reserves during the period from November 2000 to April 2002. The experience with the power reserves market is good so far, and the customers are generally satisfied with the solution.

**5. Long-Term Security – Adequacy, Diversification and Resilience**

*Electricity systems:* In a purely competitive market (i.e., without market power) without specific provision for security, spot prices are set on the short-run marginal costs (SRMC) and follow a cyclical pattern mostly determined by the long lead times to bring new supply on stream by obtaining the necessary approvals and building new plants and/or the needed infrastructures (to supply new primary fuels to the plants and to transmit the new produced power to the consumption areas). While the lead time to build new gas-fired plants is relatively short (about three years), it takes much longer, (5-6 years at a minimum) to secure an additional long-term supply of natural gas (for example, in North America today, new LNG terminals are not expected before 2007/2008) or to build power plants with high capital cost requirements (such as hydro, coal-fired or nuclear power units).

**II-1: MARKET ACQUISITION OF POWER RESERVES IN NORWAY (2000-2002)**




*Source: STATNETT*

When there is over-capacity in the system, SRMC will be low (the fuel and variable running costs of the last called unit, say, a coal-fired or nuclear plant at 1-3 US cents per kWh). When over-capacity shrinks, SRMC successively reflects the use of heavy fuel oil in boilers, natural gas in CCGT, oil distillates in single turbines or diesel in generators, rising to 8-10 US cents per kWh. When under-capacity occurs, the growing scarcity leads to a jump in electricity prices, with nearly no limit given the very low short-term price elasticity of demand. Prices can shoot up to $1/kWh and more in the case of serious and prolonged under-capacity.

Such cycles are not acceptable to consumers, especially in the developing countries where the cost of energy service is a significant proportion of personal spending, nor are the possible brownouts or blackouts which have significant direct and indirect economic costs. No matter how "liberalised" energy markets become, such impacts quickly lead to political concern or action. This is all the more true when the "natural" commodity cycle appears to be amplified by market power, resulting in even higher prices at the top of the cycle and followed by longer and more depressed prices than would otherwise occur. It is for this reason that the pure pool price model for electricity has now been abandoned in favour of long-term bilateral contracts (with price incentives conducive to investment) and a residual pool market like the one which operates in the Nordic market.

Obviously, there is a need for regulations and mechanisms which bring timely, adequate, diversified and resilient supplies of electricity into the market:

- Timely means soon enough to be available when needed;
- Adequate means sufficient capacity margin (say 15-20% at peak time);
- Diversified means using a mix of different technologies and fuels; and
- Resilient means that both generation and transmission can overcome unforeseen events.

*Natural gas systems:* The challenge here is different. Two sets of customers generally exist, small captive end-users in the residential and commercial sectors who do not have switching capabilities, at least on a short-term basis, and large interruptible end-users (industry and power plants with dual-fired capacities) who can substitute gas with competing fuels, generally petroleum products. A further difference with electricity systems is the additional flexibility resulting from peak and seasonal storage (although in some key markets geological conditions prevent their development, as in the case of Japan).

In the natural gas monopolies of yesteryear, security was often considered a strategic issue without clear economic components[29], and the costs associated with storage capacity were not specifically identified in the overheads charged to customers. For instance, in France, a part of the storage was considered to be "strategic", with the formal objective to secure, together with the ability to cut gas to interruptible customers, one year of supply for the captive sector to offset any failure in Russian or Algerian supplies.

In competitive markets, however, there is no compelling argument that security of natural gas supply is brought into question by the price-setting mechanism at the margin. One may even argue that a progressive increase in the natural gas price on the ladder of competitive fuels, from coal to heating oil, provides sufficient signals to attract new supplies before the stock of interruptible users has been entirely tapped. Fuel switching in natural gas systems comes into play earlier and with more immediate impact on supply and prices than it does in electricity systems, but this does not mean there is no need for diversification and resilience in energy systems which depend on natural gas. In a nutshell, natural gas can be stored and supplies can be interrupted in ways which give the system greater flexibility than electricity systems, but unforeseen events can ultimately have as much impact as they do on the electricity system.

**6. How to Approach the Concept of Long-Term Security?**

One may disagree with the expert opinion cited in the box below but the fact that it comes from a recognised body in a country that has actively pursued market reforms is symptomatic of the unease and concerns about supply security. The answer to these concerns has been the suggestion to create "capacity markets" operating in parallel with the commodity market. The main approaches can be boiled down to four broad categories:

- *Reliance on a central referee:* This is the "single buyer" who determines what plants need to be built and when. Security is then a "public good" with the same costs/benefits for all customers, as it was the case in the former monopoly utilities;
- *Pure competitive treatment of security:* This is a tailored service offered at competitive prices in the same way as insurance. Marketers then arrange the best possible supply/demand portfolio to offer this service at a competitive cost;
- *Ad hoc approaches:* These are efforts to combine external and internal aspects as long as they offer a pragmatic answer to the identified problem; and
- *Reliance on long-term financial instruments*: These are used to secure future supply with hedging strategies.

"Energy Market Trends in the Netherlands 2001" - ECN Policy Studies (2002)

"…In a liberalised electricity market there is no central body that determines whether to maintain old power plants or invest in new production capacity. Investment in new capacity is therefore left to the market parties. In theory a competitive market sends correct price signals to encourage investments in new capacity. There are, however, market imperfections that might result in a different reality: risk aversion and market manipulation can lead to a lack of investment in new production capacity. Firms may not be willing to invest in needed peak plants, because these plants have a low average running time and therefore provide uncertain income. Furthermore, electricity producers could intentionally cancel investments in the sector, leading to a capacity shortage that would force the most expensive power plants to be put into operation, and causing the market price to rise. Finally, at moments of extreme peak demand or due to calamities, the electricity supply could be jeopardised…"

[29] Monopolies use long-term "netback" contracts in which the price is a weighted average of the prices of competing petroleum products substituted by natural gas, heating oil for the small "captive" users and heavy fuel oil for the large "interruptible" users. Hence agreeing to be an interruptible user was a means to obtain cheap gas and a component of security even though there was no guarantee that such users had a multi-fuel capability (actually, many did not).

***a. Single buyer type system***

Such a system relies on an external operator who follows a long-term plan. It is similar to the operations of the former monopoly utilities. It seeks to minimise the total costs, including those of non-delivered electricity, at an agreed price. A slightly modified approach (with a merchant sector operating on the fringes of the single buyer) was proposed by France in the 1990s, but it was not accepted by the European Union, which preferred more competitive approaches. Today, it is an often cited design in developing countries which need simple yet independent and competitive systems in which long-term investment is guaranteed. In its simplest version (which excludes merchant transactions):

- It allows long-term planning (size, site, technology and fuel type) and security;
- It allows competition for the building of new plants (by auctions); and
- It allows competition for the running of existing plants (annual auctions, see Part III).

In particular, when security of supply is addressed externally by the system operator, there will be no herd-like rush to a single technology fuelled by a unique fuel which, in countries like the UK, is sometimes portrayed as the dash to gas. For power generation, unanimity on a technology and a fuel is potentially dangerous because large imbalances can occur in the course of only a few years. The natural gas increase in the UK, which is related to the rapid decline of its domestic fields, and the pressing need to rely on more expensive imports demonstrates the "folly" of the market in putting all or most of its eggs in the same "gas" basket. The UK is not an isolated case in this respect because, since 2000, a similar dash to gas has been underway in the USA where the rush to install gas-fuelled turbines coincides with the downturn of the domestic gas supply.

***b. Insurance type markets***

This is a 100% market approach, but it is not yet explicitly recognised as such. It calls for prudent rules similar to those applying to insurance companies – rules that would have prevented at least some of the alleged manipulation in the California market a few years ago on which there are now cases before the courts in the USA. It relies on long-term bilateral supply arrangements to build new plants and depends on the level of security that is expected from such commitments. Each contract of a marketer (aggregating several generating units) for a set of consumers (a very large industrial user or a pool of small industrial and large commercial users or an LDC) would then include the level of security chosen by the consuming entity and the price of electricity. Just as for insurance, security of energy supply insurance can be tailored to specific needs or standardised, for instance, for the small captive users. In the latter case, one would benchmark long-term security costs provided by different LDCs.

In practise, such long-term bilateral contracts will have total prices (including, explicitly or implicitly, commodity and security costs) higher than the SRMC reflected in the spot market (the commodity cost) and close to the LRMC corresponding to the load curve of the customer. Marketers would choose their portfolio of supply (generating units with the desired capacity margins and fuel diversification) and interruptible customers in order to honour their set of contracts at a minimum total cost.

While providing a competitive system for long-term security of supply, insurance-based systems are complex (for example, how does one determine the specific security cost incurred by an LDC on behalf of an existing customer?) and risky (economies of scale evidently exist and would favour market power).

Long-term contractual thinking is not new. For instance, ENRON was the first gas aggregator in the USA in the 1980s. Even earlier evidence is the practise of some LNG buyers in Japan to create a pool of buyers to commit to long-term LNG contracts that would have been too large for an individual participant. In electricity, the way the new Finnish nuclear power plant will be commercialised is similar because the output of the plant will be bought by three marketers who will have the task of optimising their supply/demand portfolios.

Competition is the driver to price such an insurance service attractively, either as a specific cost or as a "package" including the commodity and the security of supply costs. In such a scheme, because there are obviously economies of scale for providing security, the natural tendency of the industry will be to concentrate, so the role of governments is to ensure that no marketer/supplier grows too big and that suppliers have the financial back-up and guarantees to meet their liabilities, i.e. the penalties in case of non-delivery of electricity, with prudent rules similar to those of the insurance or banking industry.

In fact, in the energy business, while the word "insurance" is rarely mentioned, the concept of "penalty" is well known. It is, for instance, the obligation made by USA gas distribution companies to supply their captive customers and pay, in case of default, penalties of the order of $50-70 /MBtu. This is a proven approach that can easily be extended to the case of electricity. In the same way that gas LDCs have to secure supply for the extreme weather conditions corresponding to the one-in-fifty coldest winter, electricity LDCs may be mandated to secure enough supply to face the demand of the one-in-fifty warmest summer (when peak demand is for air-conditioning) or the one-in-fifty coldest winter (when peak-demand is for warming).

***c. Ad hoc approaches***

The absence of concern for long-term security during the earliest market reforms may seem strange in the current when most experts put a strong emphasis on the link between reliable energy access and economic development. There were, however, good reasons why things happened this way:

- First, precisely because it was felt that too much investment had been made by the incumbent utilities and that a competitive market would not undermine capital as utilities had done;
- Second, because the first wave of reforms in the UK (followed by many developing countries) concentrated on selling state assets at the best possible price;
- Third, because the choice of a pragmatic ("Anglo-Saxon") approach required all actors to adapt to the dynamics of the market rather than to carve a system in marble from the outset.

<u>An "Ad hoc" approach, that of the early British pool</u>

The first UK model was a mandatory pool, i.e., a pure commodity approach. However, as the founders rightly feared that investment could come too late, they added two elements to the costs charged to the customers, the "uplift" and a charge called "loss of load probability" (LOLP). These two extra charges were designed to increase the revenues of the producers, thus creating incentives, if not to invest more in capacity than would have been done otherwise, then at least to avoid mothballing too many idle plants*.

As these charges have been removed from the NETA (new trading arrangements), one will never know whether they would have worked if the market had been competitive. Yet it is clear that:

- Past prices were much greater than the SRMC because of market power and attracted new entrants, with "uplift" and "LOLP" playing no role in this entry;
- These "ad hoc" charges were amplifying, not anticipating, the spot price variations. Without market power, they would have come too late to avoid shortages;
- Therefore, this approach was not a good way to provide security of supply, either in terms of adequacy (capacity in time) or in terms of diversification.

* It is excellent at approaching the required capacity margin from above (too much initial capacity) but fails to encourage sufficient capacity from below (i.e., new capacity). South Korea uses it and expects to lower its capacity margin to 15%.

By definition, “ad hoc” solutions are not tailored to provide the “best” solution or to “guarantee” that they will work forever, but they are pragmatic “recipes” aimed at correcting an identified market failure. An example is the system of incentives based on the locational prices put in place by the Pennsylvania-New Jersey-Maryland (PJM) market to favour investments where they are most needed, i.e., in congested areas. However, only the long run will reveal whether this approach has led to sufficient diversification (for the time being, it is doubtful, because most new plants are medium-sized CCGT).

The setting of incentives for the early building of new capacities faces two difficulties: (1) how to calibrate these incentives to get the proper balance between too much/early and too little/late new investment and (2) how to treat incumbents and new entrants on the same footing. Regarding the first difficulty, the UK “LOLP” would not have worked in terms of timing (nor probably in terms of capacities because the incentives were too low). Regarding the second difficulty, subsidies offered to new entrants for the building of new plants may be unfair if the incumbent generators are not treated the same way and dangerous if they discourage private investors because the building of new plants before price rises will prevent this rise, kill the future expected benefits and prevent the wholesale market from covering the capacity costs of incumbents in the long run.

“Ad hoc” approaches are trade-offs that must be judged on three points:

- Whether they work in practice, i.e., whether they provide the “goods”;
- Whether they treat incumbents and new entrants on the same footing;
- Whether they create further imbalances calling for further regulatory intervention.

Capacity mechanisms are one example of the ad hoc approach. Two mechanisms exist to pay generators for their commitment to supply electricity if required:

- In the “capacity payment” system, the regulator sets a price for capacity and lets the market determine what amount of capacity will be available. In this system, the payment is chosen by the regulator, but the resulting amount of reserves is uncertain;
- In the “capacity requirements” system, the regulator sets the amount of available capacity that is needed and lets the market determine its price. In this system, the regulator chooses the level of capacity reserve, but the resulting capacity cost is uncertain.

According to the report of ECN Policy Studies, “*Generating companies can be given capacity payments with the aim of encouraging the construction of new capacity and thereby increasing total generating capacity. Such payment should cover part of the fixed costs of a power plant, removing the uncertainty about future prices covering LRMC. The system has a regulated character, which does not make it compatible with a liberalised market. Moreover, it has not been proven that it successfully improves the adequacy of the system*”.

In capacity markets, the market operator provides incentives to the generators to invest in reserve capacity and defines the maximum amount that each producer is allowed to sell. Even though these approaches deserve more analysis than can be carried out here, they have the advantage of being neutral (no generator benefits against the others) but leave some unanswered questions:

- What should the relevant time horizon be? Short-term for peak capacity requirements or long term for base load?
- Will these mechanisms bring the same capacity margin as the margin which would be achieved with an insurance or penalty-like system and the same fuel diversification?
- Do consumers who have different security needs accept the implicit “one size fits all” (with the same security premium paid by all)?
- What yardstick regulation should apply to generators if their capacity commitments are unmet?
- How will capacity payments impact the level of spot commodity prices?

Another example of an ad hoc approach is capacity owned by the system operator. According to the report of ECN Policy Studies "*This measure obliges the TSO to buy and operate power plants that would otherwise be mothballed or decommissioned. It provides a reserve capacity that would only be dispatched if the market price is higher than a pre-established maximum level. The fixed costs of these plants would be covered by the system tariff charged by the TSO to the consumers, while the variable costs would be covered by the market price. The disadvantage of this method is that it is market interventionist and thus not compatible with the current liberalised market*".

As opposed to the capacity markets that treat all generators on the same footing, the privilege granted to a last resort bidder ("Last resort option" in the EU directive) or supplier (TSO in the above ECN proposal) is unfair. By adding capacity, he lowers prices and deprives the other generators from the benefits of potentially higher prices. ECN is right in its critique: a last resort bidder/supplier may kill the incentives of the other generators to invest. On the other hand, knowing ex-ante this possibility ("threat"), investors may have an incentive to invest before the tendering is launched because they will increase their market share, "internalising" the procedure in their investment decision-making process.

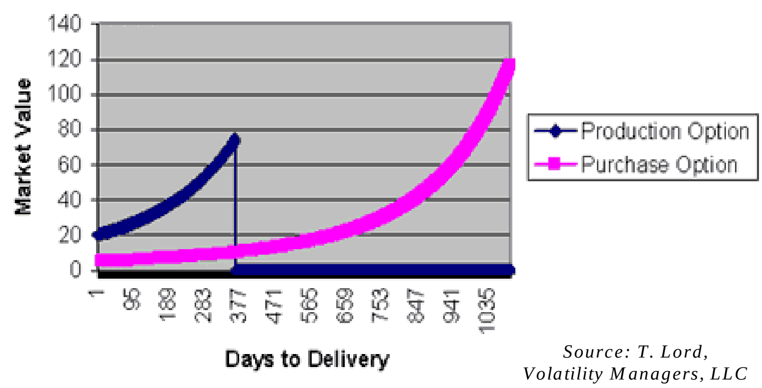
Additionally, as in Sweden, the distortion will be much reduced if the last resort option is only triggered to prevent a blackout, i.e., when the price is very high. The right trigger is the VOLL (value of lost load) because it substitutes for the lack of price exposure of the small customers who are sheltered against spot price movements by their fixed tariffs and therefore do not reduce consumption when prices are high. VOLL may also be used as a cap, with the benefit of limiting impact of market power. This said, VOLL is quite high, possibly $40-50/MBtu for natural gas and $2/kWh for wholesale electricity.

### *d. Futures markets and hedging strategies*

Price volatility and reliability (short and long-term) are two sides of the same coin. One may wonder to what extent financial hedging strategies might be used to deliver long-term security of supply and whether they will trigger investments in capacity or other reliability tools. Unfortunately, the answer would appear to be negative based on some specific analysis from outside experts.

T. Lord (*Volatility Managers* - November 2002) remarks, "*Theoretically, a stable electricity market is the solution of a real option issue but the absence of storage in electricity has profound impacts on the structure of the electricity market and on its market design. The graph below is a simplified illustration of the underlying problem of designing a stable electricity market.*

**II-2: ELECRICITY MARKET REAL OPTIONS**



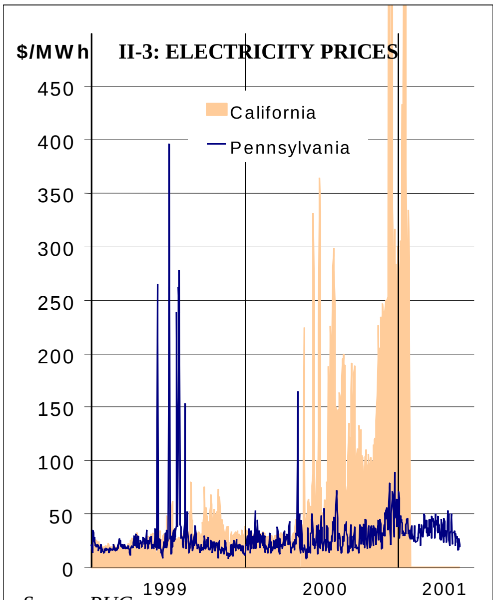

Source: T. Lord, Volatility Managers, LLC

*The ability to add new supply expires significantly before the purchaser must make the election to consume. Options to build new generation capacity cannot influence the market price for electricity once they have expired. A capacity charge covering for reliability that does not start paying when the option to build new generation exists only pays the already constructed generation capacity for its existence. So, the first market design issue for stability is to set a mechanism creating signals as much as 3-6 years before the first purchase date.*

*A market design overcoming this first issue uncovers a second underlying market design issue: credit worthiness. The credit capacity of the market is insufficient to shoulder a forward market pricing mechanism borne by the consumers that allows the cost of the real option to build generation and support the cost of long-term security. Hence the need for an industry-backed credit clearing.*

*Then, a third issue arises when the forward cost of reliability is borne by the consumers. The problem is that reliability is a long-dated forward cost that must be borne by all consumers. If the "captive" customer has the right to shift suppliers, what keeps him from walking from the obligation to honor the supplier "purchases" forward reliability for him? How can the obligation be transferred with the customer?"*

S. Gosh (CII, India – May 2003) remarks, "*Electricity is not storable and its demand is price-inelastic. These features explain why, on a competitive market, not only spot prices are volatile but also significantly diverge from a standard Markovian model (with normally-distributed random variations) in which volatility is stable over time".*



*Source:PUC*

The consequences of this "abnormal" volatility are two-fold:

1. Standard financial models (Sharpe & Markovitz) cannot be used. They are based on mean-variance arbitrages which do not apply to electricity because it has no variance per se (Graph II-3 shows the unstable volatility). Reliable and conservative strategies would be too costly because of the need to apply safeguards against volatility uncertainty;
2. Other ad hoc models exist. They are based on mimicking the persistence of successive periods with different volatilities, for instance, the ARCH and GARCH models. However, in spite of their complexity, they are not only costly but dangerous, particularly for the small users, because of their lack of theoretical justification.

### *e. Market for reliability contracts*

According to the report of ECN Policy Studies, "*This mechanism obliges consumers or the system operator to buy reliability contracts from the producers. These reliability contracts are in the form of call options that would set a price ceiling for the electricity. If the market price of electricity is higher than the option price then consumers could exercise the option at the pre-agreed price, for which they could obtain the electricity. The premium paid for the option can be seen as an income for the producer, to pay the fixed costs of the plant. The producer would be fined if it does not deliver the electricity. The advantage of this mechanism is that it is market-based.*"

This approach seems to be similar to the hedging strategies and may not work for the same reasons, i.e., because long-term prices reveal little about the possibility of future tensions (in all markets, futures tend to replicate past experience, even when strong new growth is expected). Also, futures markets, to provide a reliable bridge, would need depth (looking out, say, at least ten years) and liquidity (despite the high volatility and the risks that it creates). This has not been the case since the collapse of Enron, which has revealed the high risks (a single contract bearing a risk created by the whole market) that bankers have been willing to take as counterparts to the electricians.

The preceding review suggests that there are many ways to provide long-term security. Those relying on long-term bilateral contracts allow "tailor-made" security arrangements but prevent short-term retail competition. In the centralised security approaches "one size fits all", i.e., the degree of long-term security is the same for all, but short-term retail competition is possible. Trade-offs combining long-term diversified portfolios and the development of short-term competition without loss of security are also possible providing there remains a level field for competition.

**7. Distributed Energy and Security of Supply**

CAEM definition of distributed energy (DE)

*"A system of generation located near energy customers, possibly incorporating energy storage, energy management and combined heat and power, potentially highly integrated with the electric grid to provide multiple benefits on both sides of the utility meter".*

DE applies only to electricity because it is irrelevant for gas, which all producers sell directly to the high pressure transportation system. Nevertheless, DE for electricity has an impact on natural gas because gas-fuelled CHP units need less natural gas than large plants without heat recovery and thus contribute to increased efficiency and security of supply. Three sources of DE exist with different load contributions:

- Industrial CHP facilities that are base load units, able to sell power they don't need to the grid. This is sometimes called embedded generation;
- Random distribution of intermittent new modern renewables such as wind and solar; and
- Mid/peak load units (generating power, heat and possibly cooling for residential/ commercial users).

Depending on its load pattern, DE raises different back-up issues:

- A systemic risk when all DE facilities use the same fuel (generally natural gas). It can be lessened, especially when heating and electricity peaks coincide, if these facilities are multi-fuelled and able to switch easily to petroleum products;
- The integration of randomly intermittent supply. Wind in particular raises problems of integration and bears a systemic risk when climatic conditions are similar over a large area. West Denmark exemplifies this difficulty (See Part III);
- The implications for the grid (more or fewer transmission needs). Whereas wind requires a stronger transmission grid, CHP facilities ease the transmission needs because their back-up requests in case of breakdown are random.

To put a value on adequate back-up, two issues must be addressed and clarified:

- *The impact and the nature of expected disruptions*. If all decentralised units only use natural gas without dual-firing capacity, there is a systemic risk in case of a gas disruption, and the back-up cost will rise as a quadratic function of the size of the DE market. Conversely, if individual disruptions are randomly spread, that is, fully diversifiable by nature (different fuels, different origins, etc.), back-up will be cheap;
- *The price-setting of back-up.* Economic modelling may be unreliable; competition won't reveal this unless electricity markets are broad and sophisticated enough. Intuition suggests that as long as LDCs maintain their supply monopoly, they will try to keep DE under their control, i.e., negotiate the supply contracts and adjust the pricing of this service to their consumers using DE on a negotiated basis.

Valuing and pricing back-up correctly are necessary to create a level playing field, in particular for the conditions in which wind, an intermittent supply, should be bought. Wind has no back-up problem for small market shares below a certain threshold (their contribution is similar to the random variations that normally affect an electricity system), put at ~5%[30] market share by the West Denmark regulator for an isolated system. Above a 5% market share for wind energy, the value of elemental back-up rises exponentially.

DE has many advantages when its contribution relieves the network and increases efficiency without creating systemic risk. Conversely, DE based on poorly integrated intermittent renewables may have high costs so great that they wipe out all other potential benefits.

***a. What are the conditions for DE to develop without subsidies?***

The first important condition is to have a level playing field for decentralised units. Cost-competitive DE enjoys obvious advantages, since a more decentralised supply means less investment in the main transmission grid, the distribution grids and new additional power plants, especially if the decentralised units alleviate the peaking problems. With a level field based on cost-reflective tariffs, including the back-up supply, DE units should be able to sell any excess produced electricity back to the grid at the true avoided cost.

Should back-up be fairly priced, DE would reach a certain market share but would not replace the totality of the market because the loss of economies of scale, in particular, for the provision of "back-up", would raise its costs to the point that DE would not be not economical beyond a certain market share. Today, while there may still be room in many countries for more DE before reaching the balance between its benefits (e.g., the simultaneous provision of power, heating and cooling to a building) and its electricity and gas back-up costs, there are other countries (such as Denmark and possibly the Netherlands and Germany) for whom the playing field is biased in favour of DE, in particular, wind (because of subsidies, explicit in the name of environmental benefits or implicit in not putting a value on back-up).

The second important condition is to access primary fuels at a cost-reflective price. Natural gas, when it is cheap enough, is generally the preferred fuel for DE units. Thus if business wants to change to gas-fired DE, not only electricity but also natural gas systems should be open to competition with consistent generic rules for the two markets. If this is not the case, gas for decentralised units would be priced at the same level as for domestic/commercial customers (at the price of delivered oil distillates, for example) and would be too expensive compared with the gas price in a competitive market (roughly, heavy fuel oil price parity). The issue is not to subsidise natural gas used in CHP or other decentralised facilities but rather, to get the same pricing over time as for other uses. For instance, units calling gas on a peak seasonal basis would pay a higher corresponding price (because of the costs of storage and transportation bottlenecks) than on a base load basis.

A particular case of back-up is that of the electricity systems relying quasi-exclusively on hydro. Brazil is 95% dependent on hydro, with transmission being equivalent to exchanges of water between regions with abundant rainfalls (the case in the north in 2000) and regions with droughts (the case in the south in 2000). Given the possibilities for exchanging water across different basins and over time, because most reservoirs have 5-10 years' of water reserves, back-up corresponds to the worst case when rainfalls have been lower than usual for several consecutive years. Norway faces a completely different problem because it relies on a unique rainfall regime with little or no storage capacity. A market-based system can work for Norway because it is a relatively low-risk system based on high probabilities of small deficits, but such a system cannot work in the high-risk Brazil system based on small probabilities of high deficits.

[30] This ~5% value may look small to the proponents of wind energy, but for onshore windmills that run 1,500-2,000 hours a year, three times less than the average 60% load factor of the electricity system, this makes a three times greater capacity share, about 15%.

In summary, should an appropriate level playing field be established for electricity and gas and between transmission and generation, DE benefits will help to increase security and limit market power because they can:

- Reduce the peak stress on the transmission system, with CHP systems for buildings that auto-consume during the night and release excess electricity during the day peak hours;
- Increase energy efficiency because part of the heat that would otherwise be lost is used;
- Be used as systematic back-up (diesel generators cost less than $150/kW) as long as the primary fuel remains available (diesel or/and natural gas).

**8. The Role of High Voltage Transmission and High Pressure Transportation**

Common sense suggests that competition only exists if one can move energy from where it is produced to where it is consumed. The availability of sufficient of HV-transmission or HP-transportation capacity is not a sufficient condition to ensure security, but it is a necessary one. Should transmission or transportation capacity be insufficient, geographical niches will develop because of congestion problems, thus increasing the risk of market power because there are fewer competitors in these niches.[31]

The experience in deregulated markets teaches a second lesson. Exchanges, limited at the time of the monopoly utilities, grew in importance because of the possibilities of short-run arbitrages that drive transaction costs, including the cost of physical transmission or transportation, down significantly. However, this may only happen if capacity is available and grows to accommodate the needs of the market. Unfortunately, historically in most regions, electricity markets were developed on a state basis, with little interconnection between the different states.

In Europe, about 7% of the market is interconnected on average. The slow pace of construction of cross-border electricity links is hampering the development of a single European power market. Only a few countries (Austria, Belgium, Denmark, Netherlands) have border interconnections close to the 30% WEC experts judge to be sufficient to link spot competitive markets, which entail high volumes of short-term trading and arbitrages. In other parts of Europe, interconnectivity is low: 2% for Iberia, 3% for the UK, 7% for Italy. Even France and Germany, with about 10% and 15% respectively, are short of interconnections given their central position in Europe.

Nor has the experience in the USA of breaking up vertically integrated utilities into generation, transmission and distribution functions necessarily resulted in equal access to the transmission network. There are two reasons for this:

- First, ownership of these functions by a common owner means that the transmission function has no incentive to make life easy for competing generation or for third-party sales. FERC has rightly concluded that the independent operation of the grid is a key to success of a competitive market;
- Second, as most networks were developed on a state-by-state basis (similar to Europe) with few inter-state connections, a single market has not developed. This problem, highlighted in the following box, has led FERC to push for Standard Market Design (SMD).

[31] Congestion in the network creates the same kind of situation as that which sparked the 1789 French Revolution. At the time, agricultural goods were prevented from flowing freely from one region to the other because of customs, tolls and other barriers. The 1788-89 famine was not caused by an inadequate harvest of wheat, but because it was impossible to make up the bad crop in some regions by imports from other regions where grain in storage was rotting.

EEI: "*Utilities Seek to Overcome Problems Related to Aging Energy Infrastructure*"

*"In the US, aging infrastructures - generating plants, thousands of miles of HV transmission lines, transmission towers, and distribution facilities - are starting to raise concern among utility and transmission company executives, who are straining to find a solution that won't break the bank".*

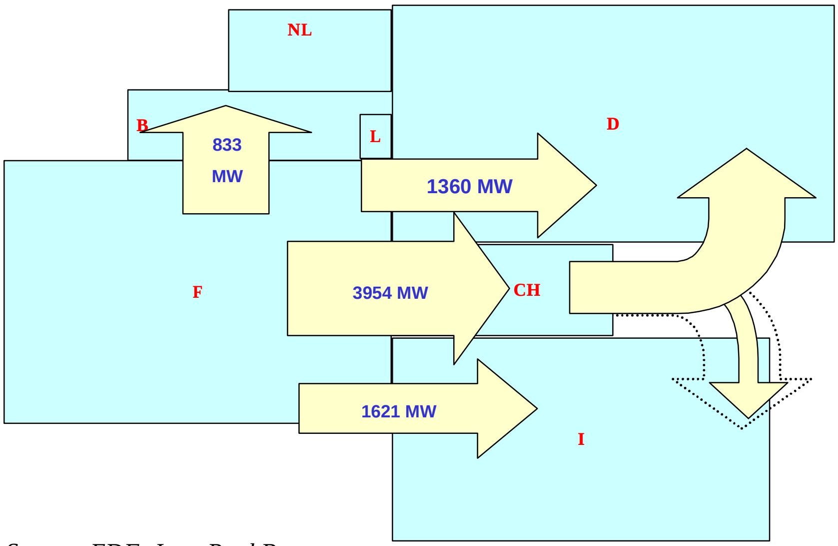
*"Most of today's transmission systems were not designed to deliver large amounts of power over long distances. The grid, built originally to interconnect neighbouring utilities, now is being used as a 'superhighway' for electric companies. The number of transactions on the grid has increased significantly because of competition. As a result, the transmission system is facing dramatic increases in congestion, which threatens system reliability and increases costs to consumers. It is clear that new and upgraded transmission lines are needed now to meet the demands of a competitive market".*

In Japan, the situation is not any better in terms of transmission capacities among the seven monopoly areas. For instance, TEPCO, the largest utility, has interconnectivity of less than 7%. Its total installed generation capacity is 57.8 GW, but its interconnections are only 2.5 GW with Kansai (30.1 GW installed), 0.3 GW with Horukiru (5.2 GW installed) and 0.6 + 0.3 GW with Chubu (25.4 GW installed), which operates at 50 Hz, whereas the others operate at 60 Hz.

***a. Economic significance of high voltage transmission grid***

High voltage electricity transmission is a small part of the total electricity cost. The average split among generation, transmission and distribution is 50-70% for power generation, 0-10% for HV transmission (depending on the degree of interconnection) and 30-50% for distribution. Yet, transmission cannot be managed in isolation because the strength of the electricity chain is the strength of its weakest link.

**II-4: COMMERCIAL ELECTRICITY FLOWS IN EUROPE - AUGUST 2001**




*Source: EDF, Jean-Paul Bouttes*

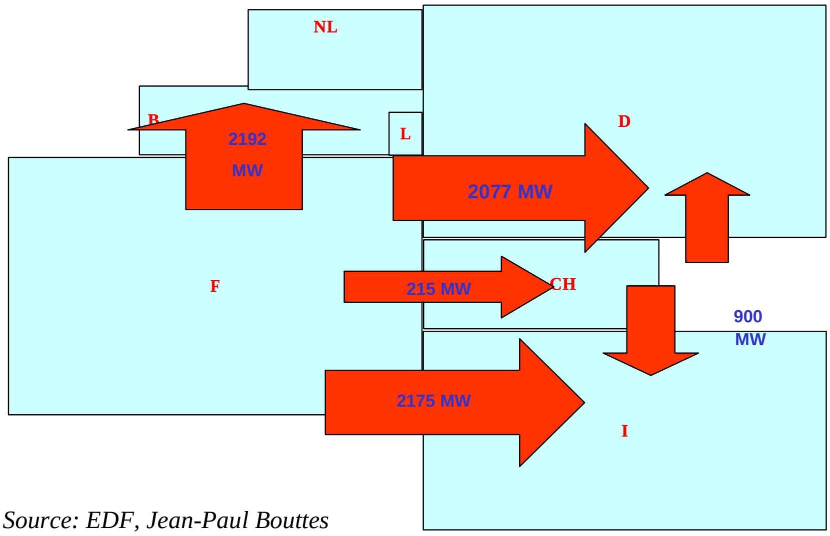
A simple reliability analysis may be applied to electricity systems:

1. Reliability is provided at minimum costs when a marginal investment in any of the three links has the same effect in terms of reducing the probability of a system breakdown;

2. In turn, given the respective 60%, 5%, and 35% economic weights of generation, transmission and distribution, this calls for a proportionally higher investment in the grid and a smaller probability of break-down proportional to the share of investment.

This simple rule of thumb is displayed in Figures II-4 and II-5. Electricity transmission is technically complex because electrons follow a physical not a commercial path have two implications:

**II-5: PHYSICAL ELECTRICITY FLOWS IN EUROPE - AUGUST 2001**




*Source: EDF, Jean-Paul Bouttes*

1. That transmission needs over-capacities, the more so because competition increases the volume of commercial flows, and
2. That simple tariff systems should always be preferred to sophisticated approaches unless they are designed to cope with transmission bottlenecks.

As J. Vasconcelos, Chairman of the CEER (Council of European Energy Regulators), has said, "*Liberalisation cannot be separated from market integration*". Yet the gloomy reality in many regions, in particular Europe, as shown by the small inter-state flows, is that transmission congestion is the rule rather than the exception.

### *b. Dealing with congestion problems*

The lack of transmission capacity and how to increase it to reach levels of interconnectivity consistent with a regional competitive market are key issues. In practice, the circumstances in which electricity cannot flow freely because of the lack of transmission capacity may be addressed by limiting the flows (with the extreme solution of not starting the liberalization process while congestion problems are severe) or by increasing the transmission capacity.

Market "splitting" or virtual "counter-trading" may be used to address congestion. Market splitting exists in the Nordic market and is also the basis of the most sophisticated "nodal pricing" approach. In virtual counter-trading as it exists in Finland, the TSO, even if it cannot fulfil a transaction because of the lack of transmission capacity, has to deliver the supply and shoulder the cost of replacing whatever cannot be transmitted and is bound to the same delivery point and cost.

Unfortunately, congestion pricing does not limit the market power that fragmented markets create for the generators. It can even be counter-productive if it is not correctly designed and managed. For instance, according to the analyses developed by Professor Glachant, the Swedish TSO is a direct beneficiary of the congestion situations with the other Nordic countries. What really matters is whether there are incentives to invest in new transmission (for which the allowed returns need to be attractive) and to proceed quickly (for example, by allowing merchant lines in situations where the grid owner is too slow, as now seems to be the case in Italy).

To develop competition, two conditions need to be fulfilled:

- Congestion charges should create incentives for building what is the cheapest solution between a new plant and new transmission lines[32];

[32] The balance of costs is generally in favour of cheaper siting costs of new power plants over the reduction of transmission lines. Nodal pricing (also called "locational pricing" in US terminology) brings the risk of the opposite, i.e., to favouring the creation of new plants in the niches created by congestion over the development of new regional transmission capacity.

- Investment decisions cannot be held hostage to unreasonable external or political barriers, such as NIMBY or BANANA, for which no amount of factual data is likely to change the attitude[33].

If not enough transmission capacity is secured and congestions occurs, the best strategy would be to:

- Let prices signals shoot up, even if market power contributes to the hikes, but ensure that marginal prices are transparent and merchant lines can be constructed; and/or
- Rely on DC lines that face fewer implementation constraints (many DC lines already exist or are planned in some regions, such as those by Italian industries between Italy and France.

***c. Transmission pricing: SRMC or LRMC?***

Pricing is always important and must be set at a level that creates the incentives to maintain and develop the network. It is even more important when congestion is severe, because by increasing reliability problems, congestion leads to more regulatory intervention that may undermine investment incentives for the rest of the system. Transparent pricing to allocate transmission rights is needed. A first-come first-served allocation rule is unfair because it splits the market between the "haves" and the "have nots", forcing the latter to compete for what is left (uncommitted or released capacity rights), generally at higher cost. It is to provide for non-discriminatory access that legal unbundling has now been adopted by the European Union and the USA FERC.

If unbundling is effective, the theoretical solution to congestion problems is to disallow reservation and to allocate the totality of the capacity through a tender process. But this approach faces practical constraints of time and information asymmetry, therefore calling for workable, if not perfect, compromises, exemplified by the current Nordpool or PJM systems. In practise, the allocation of congestion costs with time-of-use nodal pricing is a SRMC-type approach. It should hopefully remain exceptional, because the need to use it reveals a structural lack of transmission which is a fundamental flaw of a competitive system and should preferably be solved before launching competition.

Another drawback of time-of-use nodal pricing is to favour new DE (distributed generation) against new transmission, thus not only ruling out the increase in resilience and supply security that interconnected regional networks provide but also contributing to lower diversification and higher reliance on distributed gas-fueled solutions[34]. In this regard, as noted by a commentator, the proposed FERC Standard Market Design (SMD) "*…may do little to increase transmission capacity since the locational marginal pricing (LMP) will usually be easier for producers to capture by adding local generation than through the construction of any major transmission facilities, the more so because adding transmission facilities to remove a constraint would also kill someone's goose! It is the re-dispatch of distributed generation added in a constrained area which the FERC is relying on to allow the concept of transmission congestion charges to work. Hence, a likely outcome of SMD will be to encourage more development of distributed generation to take advantage of LMP, rather than significant transmission investment*".

In the absence of congestion, transmission should be priced on the basis of LRMC because, especially in the fast growing markets of the developing countries, availability of new transmission capacity in time is vital and calls for economic incentives that cover the full cost of new capacity.

[33] NIMBY is the acronym for "Not In My Back Yard" and BANANA for "Build Absolutely Nothing At any cost Near Anybody" More and more, even in developing countries, there is local opposition to new lines. Tendering different possibilities may help to find an acceptable solution by the local communities in terms of property and transit rights at the lowest cost.

[34] For natural gas, the network must adapt to where the supply is located, but for electricity, one often has a choice between adding a new plant locally or increasing the transmission capacity. A possible answer is the combination of large centralized units for base-load supply and smaller decentralized units for mid-load (seasonal or day-night patterns) needs.

As noted above, a simple way is to use the "postage stamps", i.e., entry/exit charges,[35] which may be modulated regionally as follows:

- High entry charges for remote power capacities or gas supply, i.e., far from consumption centers, especially if existing transmission lines are close to capacity;
- High entry charges for consumption areas, especially if they rely on remote sources of power or gas;
- Low or even negative charges for the plants or consumption centres that do not require additional transmission capacities, or can even alleviate the constraints on the existing lines.

Even a simple modulation of regional entry/exit charges reflects the locational component and creates the incentives for the "right" decentralized decisions to locate new supply and demand investments.

"Right" decisions are those which minimise the cost of supply, a cost that not only includes generation but also transmission and security. The incorporation of security is important because it allows the right arbitrages between the reliance on local DE (distributed electricity) and remote, diversified, power plants to be made. Large interconnections are, furthermore, a *sine qua non* of sustainable energy market integration. This is important everywhere, for instance, in the USA or the European Union, but even more so in developing countries because the value of "common" regional energy markets is enhanced by commonly agreed rules which, once agreed, are the powerful basis of regulatory stability, lower risk and affordable energy services.

***d. The case of HP natural gas transportation***

Natural gas is simpler to trade than electricity. Whereas electricity cannot be stored, has a highly inelastic demand and follows physical paths that spread over the entire grid, gas is more flexible, follows the pipes and has prices reflecting what, when and where inter-fuel competition takes place through the storage and transportation costs. Inter-fuel competition works the same way in all countries, even though North America stands apart because of its much lower storage and transportation costs than elsewhere.

Regarding USA transportation costs, pre-reform transport tariffs were based only on long-term capacity reservations. They first evolved towards a mixed formula including both a capacity element and variable costs (the "straight fixed variable" formula). However, this formula proved to be inadequate because the regulated tariffs were either too high in an overcapacity situation (e.g., during the low-demand summer season from March to November) or too low for the situations of bottlenecking due to a lack of capacity (e.g., during the high-demand winter season from November to March).

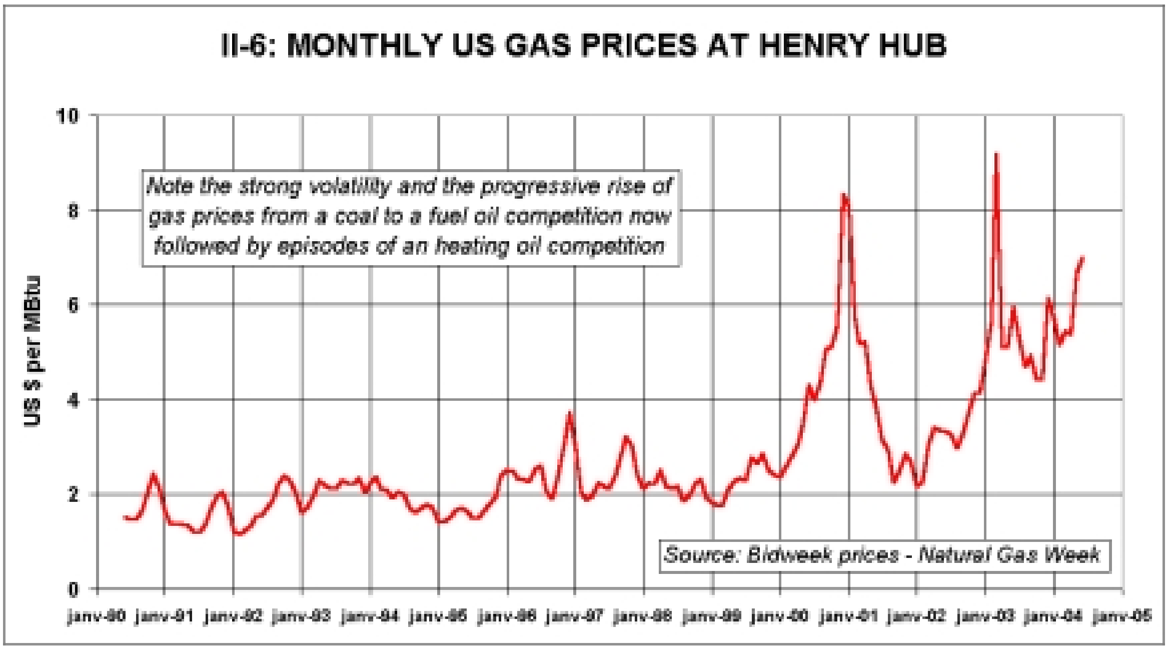
A second evolution happened in the 1980sas shown in Graph II-6. After the NGPA of 1978 (that progressively decontrolled the prices of "old" gas), the bundled pipeline companies (performing the aggregating, transport and supply functions) had contracted largem high-priced quantities and were confronted with a falling demand (1980-85). Being close to bankruptcy, they accepted their unbundling in exchange for being relieved from these supply contracts. This led to the creation of two competitive markets: the wholesale market, where prices fell to the level of coal competition in 1986, and transportation, with a pipeline-to-pipeline competition that resulted in lower transportation costs:

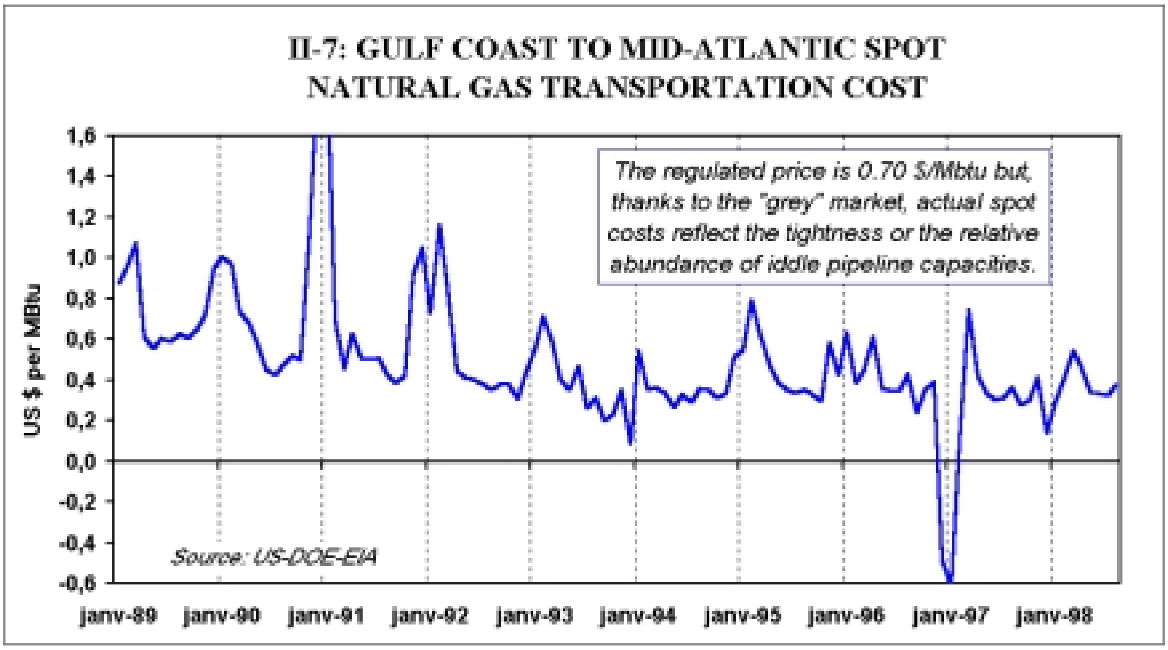
- Short-term pipeline-to-pipeline competition in the pipelines on a same route pushed transportation costs from Louisiana to the Northeast from $~0.7 /MBtu (official rate) down

[35] This method has also been criticised on the grounds that it does not reflect the cost of bulk power over long distances. Transfers entering one network and exiting at the other boundary do cause losses that may justify the pancaking of wheeling charges. Yet, if two counter flows exist, the net effect is close to zero and should not be charged. Even simple approaches to tariffs have problems

to less than $0.4 /MBtu in summer when pipes were under-filled, but despite the over-fill during winter, prices could not go up because they were capped by regulated tariffs. This is why the "grey" market appeared;

- In this "grey" market, marginal gas quantities were sold directly at the delivery point (city gate) at a price reflecting both supply and transportation costs. The marginal transportation cost was the difference between the entry and exit gas prices and was higher (up to $2/MBtu) than the capped tariff. Even though it was only paid for the marginal quantities traded in this "grey" market, the pipeline expansions of the 1990s suggest that the corresponding SRMC-type signals provided incentives to increase capacity (the following box illustrates this "grey" market).




NB. In Graph II-7, the blue values are average monthly costs, the green ones are annual average costs and the red curve is the smoothed trend. The decline in the cost of transportation has been shouldered by the pipeline companies; they continued to make profits and increase transportation capacities when bottlenecks, signalled by the "grey" market, created opportunities to invest. Pipeline-to-pipeline competition has resulted in leaner costs that have favoured producers, shippers and consumers.

In Europe, three different types of capacity allocation and pricing methods are applied depending on the specific conditions, in particular, the share of gas traded across borders (today, 60% of the supply is traded across at least one border, a figure set to rise because of the decline of domestic production):

- A point-to-point regime in which capacity is booked on the path linking the entry to exit points;
- Entry/exit in which the entry and exit points are dissociated when booking capacity on the network;
- Hybrid regimes with a mix of notional path and entry/exit charges.

The real problem in continental Europe is that there is no pipeline-to-pipeline competition (except in some areas of Germany) nor supply competition because the access to common facilities, pipelines and storage remains difficult. While some access remains under negotiated terms, even regulated access does not yet allow spot transactions for interruptible contracts, even though the USA and UK examples show that they are at the heart of the emergence of a spot price regime. According to the European Commission, "*Member states and national regulatory authorities will need to ensure that transmission and distribution operators reply to access requests within a reasonable period of time. In the Commission's view a period of two weeks should, in principle, not be exceeded*". One is still far from an electronic bulletin providing all capacity availabilities nearly instantaneously.

Free access to the grid is the key to achieve competition in the gas sector and requires regulations to:

1. Unbundle transportation services and long-term supply contracts. After the USA (1980s), it was imposed upon BG in the UK in the 1990s because it was an obstacle to competition;
2. Release part of the gas supplied in long-term contracts to third parties (that was done in the UK at the expense of BG and in Spain at the expense of Gas Natural);
3. Allow short-term interruptible transactions between the LDCs that have an obligation to supply and the large industrial users who can switch to other energies.

**US Natural Gas Market**
**An Assessment of Capacity Release following the Removal of Price Caps**

In early June 2002, FERC staff released a paper detailing its findings and seeking comments from the natural gas industry on a regulatory experiment lifting the price caps on capacity release transactions on natural gas pipelines (i.e., officialising the grey market) during the two-year period extending from October 2000 to end September 2002. This paper said:
"*Overall, the staff paper found that the capacity release experiment did not lead to large increases in capacity releases over the price cap. Still, FERC staff found that during peak demand periods for pipeline capacity, the percentages of releases above the price cap did increase. FERC said it found 713 releases above the price cap with an average total volume of 4.3 Bcf/d. The biggest single day capacity release volume totaled 570 Mcf/d during October 2000 with the most recent releases in December 2001 at 126 Mcf/d….Above-cap releases made up about 2% of the total number of capacity releases and 2% of total capacity release volumes, and took place during the winter of 2000-2001, when natural gas prices spiked to $10/MBtu and higher in some places….In a refutation of pricing concerns, the report found that while above cap releases were taking place, there were usually other releases for the same markets that were at, or below, the maximum rate. As a result, in spite of the lifting of price-caps, the average release rate for all releases into that market was usually below the former price cap, and the prices for capacity release transactions followed the actual costs of transportation on the pipelines….Responding to concerns that lifting price-caps would lead to abuse of capacity in favour of marketing affiliates, the staff noted that this was unfounded*".

The next month, in July 2002, the main comments about this experiment were submitted to FERC and published in the media (Reuters):

- ExxonMobil, Shell, Conoco and ChevronTexaco urged FERC to end the two-year experiment and re-impose a rate cap on released transportation capacity to prevent anti-competitive behaviour by pipeline owners. They said that:
  - "*the FERC staff paper analyzing the results of the experiment was 'flawed and incomplete' and showed why the market was not competitive enough for uncapped rates,*
  - *a few rates charged by pipelines were as much as 800 percent over the old cost-based rates, even during the off-peak month of May,*
  - *without a price-cap, prices may even be driven higher in the future than those reported because conditions were ripe for affiliate abuse,*
  - *the pipelines do not have an incentive to refrain from this anti-competitive behavior*".
- The National Association of State Utility Consumer Advocates said it wanted FERC to continue its experiment for another two years to gather data and reassure consumers that the energy markets were being policed.
- AGA (American Gas Association), which represents many US utilities and gas storage operators, said in its comments to FERC that it was in favour of a permanent price cap removal or, alternatively, a five-year extension of the experiment. They also brought other comments:
  - Removal of the price cap creates a market indicator to where capacity additions are possibly warranted, and the indicator would be an important benefit in today's challenging climate for infrastructure development and natural gas supply portfolio management.
  - The two-year data showed average rates for all capacity release transactions of $0.19 per MBtu, compared to $0.26 per MBtu average maximum ceiling rate and that the number of deals above the capped rate reflected periods of scarcity rather than the exercise of market power.
  - There is no factual basis for concern of abuse by the pipeline marketing affiliates in the short-term secondary market.

**Examples of the way transmission is organised in IEA countries (Source: IEA)**

| Country | Model? | Who owns? | Who plans? | Who permits? | Who develops? |
|---|---|---|---|---|---|
| **Australia Victoria** | Transmission company | GPU Powernet | VENCorp | VENCorp | Competitive bidding by independent companies |
| **Denmark** | Transmission owners | Elkraft, Eltra & regional Transcos | TSO, Elfraft, Eltra | Danish Energy Agency | Transmission owners |
| **Finland** | Transmission company | Fingrid | Fingrid | Fingrid | Generally Fingrid |
| **France** | Vertically integrated company | EDF | GRT within EDF | Energy Minister & Regulator | GRT within EDF |
| **Italy** | TSO (GRN) | ENEL & others | TSO (GRN) | TSO (GRN) | Transmission owners |
| **Japan** | 9 vertically integrated companies | Nine EPCOs | EPCOs | Energy Ministry | EPCOs |
| **New Zealand** | Transmission company | Transpower | Users | Users | Competitive bidding by independent companies |
| **Norway** | Transmission company Statnett | Statnett | Statnett | Energy Ministry (NVE) | Generally Statnett |
| **Spain** | Transmission Company (Red Electrica) | Red Electrica & others | Red Electrica | Ministry of Economics | Competitive bidding by independent companies |
| **Sweden** | Transmission company (Svenska Kraftnƒt) | Svenska Kraftnƒt | Svenska Kraftnƒt | Svenska Kraftnƒt | Svenska Kraftnƒt |
| **UK, England & Wales** | Transmission company (NGC) | NGC | NGC | NGC under expenditure allowance set by regulator | NGC |
| **US, PJM** | ISO-PJM | Seven transmission companies | ISO-PJM | ISO-PJM | Transmission owners |

## 9. Summary of Part II: Security of Supply, The Wider Challenge

Energy security is what makes the difference between energy being seen as a commodity and energy being seen as an "essential" good for welfare and economic development. It can be provided in many ways via larger capacity margins, distributed energy or regional network and needs to cover three aspects:

- Quality and reliability of the supply;
- Adequacy of the supply from a long-term perspective;
- Resilience of the energy networks.

With the recent supply crises in some industrialised countries, security has become a key concern that now dominates the question of market design. Of course, for two billion people in the world (mostly in developing countries), this is ironic, since they live day-to-day in a permanent supply crisis, with no access whatsoever to commercial energy services; another two billion people in these countries have periodic or unreliable service. In the USA, where the momentum in favour of retail competition has stalled, the ongoing discussions focus on the possibility of imposing mandatory reliability standards defined by NERC (North American Electricity Reliability Council). In the EU, the debate over "reliability" has not reached the same level of urgency, but it is envisaged in the move to retail competition which is taking place there.

One might summarise the messages of Part II as follows:

*Quality and reliability of supply* is the responsibility of the system operator. The main features of this responsibility are the fine-tuning of the balance between supply and demand given all the deviations from the initial plans and the management of ancillary services, such as reactive power/frequency for electricity or pressure for gas distribution networks. These tasks are similar to those of the former utilities, except that the capacity reserves are mostly in the hands of third parties and must be paid for.

*Long-term adequacy of supply* may be approached in different ways, decentralised or centralised, systematic or "ad hoc", etc., providing that all generators are treated the same way. Guaranteeing that sufficient capacity margin will be available on time has become a much discussed issue in the EU and in other developed countries that are already engaged in market reforms, with the question remaining of whether the design of wholesale markets provides security or needs to be adapted. Some experts fear that too little investment may come on line and that sooner or later, problems will arise. However, many others believe that security will not become an issue. They may be right because of the imperfect nature of electricity markets in which the major actors can, to a certain extent, control the outcomes in terms of prices and investment.

*Resilience of the energy systems* has two sides: diversification (fuels, fuel sources and technologies) on the one hand, and redundancy of some essential transmission or process facilities on the other hand (to avoid the risk that a breakdown of a single facility could interrupt all supply). Regarding diversification, the fact that marginal electricity prices increasingly reflect those of gas (convergence) means that electricity producers cannot expect to build long-term rents without diversifying out of CCGT fuelled by spot gas, which will push them to invest in base-load technologies (hydro, coal, nuclear) or rely on a gas price formula different from spot. Regarding transmission resilience, the recent blackouts or the cascade of electricity meltdowns from Ohio to the whole Northeastern US and Canada will certainly trigger actions for the grids (even though these problems have little to do with the design of competitive energy markets).

In all security of supply respects, distributed energy and regional integration are closely related because security has local and regional dimensions. Local supply with decentralised units is a first-rank insurance but needs the consolidation of a second-rank insurance, a deep regional market to provide back-up. The larger the region accessed by the grid, the more secure the back-up. Regional integration is a key issue in the EU by the very nature of the dynamics of the “single market”; in the USA and Canada, with the “Standard Market Design” proposed by FERC to increase the interstates flow of electricity; in Japan and in Australia. Developing countries are also moving ahead, either because of their size (Brazil, China, India), or because groups of states (such as those in Latin America for some time and now in Africa) recognise the benefits of integrating their energy markets, not only to increase the resilience but also to create a more stable and less risky institutional framework. It is a simple fact that, while common rules agreed among several countries are difficult to negotiate, once established, they are also more difficult to change and therefore they are more attractive to potential investors.

## PART III: WHOLESALE MARKET DESIGN

### 1. National/Regional Trade-Offs

The first two parts of this report concentrated on distribution and retail and on security of supply. The importance of these two subjects, long neglected and considered as secondary in energy market reform, has now been recognised. This does not mean that the introduction of reforms in the generation sector and the creation of wholesale markets are less important.

In fact, the creation of sustainable wholesale markets for energy services was the core issue of early energy market reform and led WEC to deliver the strong messages set out in the box below.

**Lessons of published WEC reports on electricity market design**

- Competition at one stage, e.g., in generation, may compromise competition at another, e.g., to construct capacity. <u>Priorities must be established</u>.
- A blend of market and regulated features may simplify market reforms. <u>Complex market designs do not necessarily deliver greater benefits.</u>
- Modifications will be needed to achieve other policy goals, such as social, environmental and long term planning. <u>There must be compromise between the level of competition and energy policy goals.</u>
- The circumstances of each market or region can be quite different. <u>Keep energy market reform as simple as possible!</u>

Compared to these recommendations calling for clarity, simplicity and leadership, the many regulations made to correct the deficiencies of energy market reforms in different parts of the world cannot be said to be clear or simple. They have created uncertainty. As shown in Part II, the stability of reforms to limit the regulatory risk has become more important because the confidence in deregulation has faltered and the mood of stakeholders has turned sour. A recent poll conducted by Cap Gemini Ernst & Young found that 40% of senior executives are now less positive about the prospects for deregulation. Together with the market intervention by regulators and governments, the loss of liquidity in the wholesale markets was among the most often quoted negative points. Another concern was the challenge of implementing reforms, with some companies unable to comply with new regulatory rules.

Among the difficulties is that, when it comes to energy market reform, one size does not fit all. National circumstances call for tailor-made trade-offs. A first difficulty is the adequacy of the framework conditions in developing countries (mainly, the legal and judicial system including such basic issues as property rights, respect of contracts and the degree of independence of regulatory agencies). Mother Nature also plays an important role in terms of resource endowment because domestic availability of hydro (e.g., Brazil, Norway), coal (e.g., China, India, the USA) or natural gas (Algeria, Canada, Russia) leads to different problems related to the technology/fuel mixes involved in the provision of energy services.

A second difficulty is the variety of designs that have been tested here and there: in the UK, the Nordic market, California, Germany and the different markets in the USA and Canada. Their analysis and comparison should be based on a full-time cycle of reforms, including the building of new capacities. Unfortunately, experience with current reforms is quite recent, barely ten years for the Nordic market (a period during which no new investment has taken place) and even less elsewhere, with the result that it is not possible to make definitive comparisons and judgments on energy market reforms.

In light of these difficulties, one might set a new agenda for energy market reforms with four headings:

- Ownership: public or private?
- Market power: how to prevent or control it?
- Design: how much and how should competition be introduced?
- Public policies: how to implement without distorting the level playing field?

**2. Upstream/Midstream: Ownership and Unbundling?**

The historic rationale for choosing the vertically integrated utility model has changed. The former economies of scale have become "diseconomies" of scale with the emergence of gas turbines and CHP. Networks remain natural monopolies but are now challenged on their margins by merchant investors. Publicly owned utilities increasingly face governance problems with evidence that, unless such companies are allowed to operate in a full commercial setting in terms of employment and rates of return, the "public service" goals of such companies could be better performed by privately owned utilities. The internalisation of contracts to avoid complex and cumbersome management, which was the "raison d'être" of the integrated utility model, has now been challenged.

In the vertically integrated utility, generation, supply and transmission were bundled because it was easier to deal internally with such touchy trade-offs as siting/building new generating plants versus reinforcing or extending the transmission grid. It was perceived that an integrated utility lowered the risk of mismatch between investment/operation decisions made in the grid and those made in the supply. It is true that, in such a model, the global risk is theoretically minimised; however, in this case, the risk is entirely borne by the final users - the taxpayers - and this has been acceptable to the extent that the monopoly has been well managed. However, the growing governance problems of publicly owned utilities, particular in terms of their employment flexibility but also now in terms of access to investment capital outside government sources, reveal that their global risk has increased, with the result that final end-users could be better off with unbundling. What is often overlooked, however, is that unbundling itself brings new risks in the form of the need to coordinate and manage separately owned components of the energy system, resulting in calls for appropriate regulations covering all the responsibilities so there are no gaps which could be detrimental to the safe and reliable workings of the system. The irony is that, with a move to privately-owned utilities with or without a "public service" component, the need for regulation increases rather than decreases.

***a. Risk and cost of capital***

Even though the cost of capital was not always an explicit argument in favour of monopolies in the past, one has to remember that the lower the risks, the cheaper the cost of capital. The origin of capital matters less than the level of risk. A private monopoly with a perceived stable regulatory framework, such as that of the early USA investor-owned utilities (IOU), has almost as little risk as the same company in public hands.

The expected cost of, or return on, capital "R" is the weighted average of the costs of equity and debt (with the latter being reduced by income tax since interest is generally deductible). Both the percentage and cost of equity depend on the level of risk: the higher the risk, the higher the cost of equity and the lower the leverage by debt. For instance, the USA IOU had an equity cost of about 10% and a leverage of up to four (that is, debt four times higher than the equity). The cost of their debt (bonds) was, say, 6% pre-tax and 3¾ % after-tax, making a weighted average of $10*(1/5) + 3.75*(4/5) = 5\%$.

This value is the annual return expected on invested capital (discount rate used for investment decisions). It plays a very important role in capital intensive industries such as energy because, as shown by the value of the constant annuity of an investment, the higher the cost of capital, the higher the annuity. The approximate formula of the constant annuity "A" of an investment with a capital cost of "C" to be recovered over "N" years and bearing a return on capital "R" is: $A/C \sim 1/N + 0.6*R + AOC$ (annual operating costs expressed as a percentage of the investment capital cost C, say, 3% for this example).

Thus, in practise, the annuity is:

- For a risky investment at 15% per annum over 20 years, A/C ~ 5% + 9% + 3% = 17%;
- For a low-risk investment at 5% per annum, A/C ~ 5% + 3% + 3% = 11%.

Depending on the risk of the investment, the annuity can be quite a bit lower and leads to different investment decisions, short term based in the case of high capital cost, long-term-based in the case of low capital cost. A rule of thumb is that the economic horizon is the reverse of the interest rate. For a 15% discount rate, the horizon is about seven years, consistent with the building of a CCGT, but certainly not with that of coal-fired, hydro, nuclear plants or transmission lines. Conversely, a 5% rate extends the time horizon to twenty years, a time horizon more compatible with the capital intensive nature of a wide range of supply sources in the energy industry.

***b. What are the risks? What are the benefits?***

The preceding analysis explains why the former choice was to prefer vertically integrated monopolies, either state- or investor-owned (the latter has a good record in the countries where a strong tradition of regulation exists). Nevertheless, as discussed in Part I (related to distribution), pure monopolies or even more publicly owned monopolies have little incentive to raise their efficiency, and sooner or later they run into governance problems.

Thus even though unbundling and competition are riskier and the cost of capital is greater when the business is unbundled, the pendulum increasingly has swung in favour of reforms because the added cost of the risk premium caused by market reforms is more than covered by improved efficiencies and higher quality service. This judgment does not preclude, however, the consideration of specific circumstances and how far to push market reforms in the following areas:

- What degree of unbundling?
- What degree of privatisation?
- What degree of competition?

For developing countries or former centrally planned economies, one of the greatest risks borne by foreign investors is the currency risk. It was mentioned in Part I (related to distribution) but also applies to generation and transmission. Using hard currency borrowings to fund soft currency sales can be a recipe for disaster. Using government guarantees is rarely a solution, as the relevant governments often do not have the financial capacity to meet them. Attracting local currency funding is an important element in addressing this issue. Exceptions exist, but often there are significant domestic savings in developing economies, although they may not be available in a form that is accessible for infrastructure funding. Hence the creation of long-term savings institutions is an important contributor to the creation of energy and other infrastructure in developing economies.

For developed countries, nuances need to be introduced on the question of public ownership. While Part I argues strongly in favour of privatisation for energy distribution, is it indispensable for generation, in particular, nuclear or hydro, or for transmission? Is a 100% privatisation, a partial opening with a majority stake (51%) or a minority golden share (e.g., 25%) equivalent for generation and transmission? Another dimension is whether the management responsibility only or both management and investment responsibility should be placed in the hands of the private sector. Lastly, is a level playing field truly possible when state and privately-owned companies compete side by side?

There is no single answer to these questions, which can be applied in every country. National circumstances play a fundamental role. For the France of the 1950s, the EDF public-owned monopoly was a good system as the investor-owned utilities were for the USA at the time. Part of these designs may still be relevant for a country like Brazil, with over 95% dependency on an integrated hydro system. As discussed in Part I, there are no compelling economic arguments against the privatisation of distribution companies, but there may be good reasons to rule out or delay the privatisation of power generation or transmission in some less advanced countries.

In reality, when it comes to energy market reform, the choices which confront governments are not just about ownership (public or private) or about the unbundling of the different upstream, midstream and downstream sectors. The challenge is also, and more importantly, how to link ownership, unbundling and regulation. It is regulation which should correct for the potential drawbacks of unbundling, and regulation should not allow the utility owner, public or private, to be the only decision-maker for new investments. Contestability is needed, even for investment in transmission.

***c. Regulation versus unbundling***

In Part II (devoted to security of supply), the role of the grid (high voltage transmission or high pressure transportation) is discussed mostly in terms of reliance on remote/diversified supply and resilience. However, two other aspects play an important role in the workings of electricity and natural gas systems. The first is the impact of congestion to create niches in which market power is more likely to develop because there are only a few local competitors; the second, as a corollary, is the design of a wholesale market that may limit or avoid the risk of market power when constraints exist in the grid.

In other words, the design of the wholesale market and regulatory control over the grid are interdependent. An appropriate set of regulatory incentives will contribute to the development of the grid, especially when bottlenecks need to be overcome, while poor regulatory design may delay or sometimes prevent the construction of new lines. The problem is compounded by the increasing difficulty of building new HV or HP lines because of public and environmental constraints[36]. The example of Italy shows that the transmission bottlenecks were worsened because the decision-making process for new grid investments was longer than it should have been.

On the other hand, easing the construction of new lines may discourage the development of distributed energy even when the latter would be less costly and more secure. The reconciliation of transmission and generation objectives requires a balance between the cost of the grid, the benefits of economies of scale, the greater efficiency of local CHP, the risks of market power and the overall security. What is clear is that trade-offs or compromises will be needed; the “perfect” market does not exist.

Part of the required balance is in the hands of suppliers (due to their responsibility for long-term security), but there is also a role for operators and associated regulatory authorities. This is why the independent system operator (ISO) model, with ownership of transmission assets in the hands of a separate entity, has increasingly been abandoned in favour of the transmission system operator (TSO) model with operation and ownership of the grid in the hands of a single public or private company. The trend toward the TSO model has several positive impacts because of the integration of the core functions of planning and investment, outage management and management of congestion in the same hands which lowers transaction costs (the “internalisation of contracts”) and ensures, at least theoretically, an optimal management of the transmission-generation interface.

The optimum regional balance between transmission and generation investment is so important that one must stop thinking of network access as a matter of cross-border trading but as an issue of regional network (electricity and natural gas) - the backbone of the region-wide market, for which a regional transmission operator (RTO) must ensure that network tariffs and access procedures are transparent and uniform[37]. A further evolution is even possible with the TSO/RTO becoming an

[36] The “NIMBY” (Not in My Back Yard) or “BANANA” (Build Absolutely Nothing Anywhere Near Anybody) syndromes.

[37] For instance, in the case of congestion, the prevalence of long-term contracts, or the “first come, first served” approach, may result in only a small fraction of the energy being freely traded across borders.

ITC (Integrated Transmission Company) which owns the transmission assets, operates the transmission functions of the wholesale market with a strong regulatory interface and is responsible for investment in new transmission.

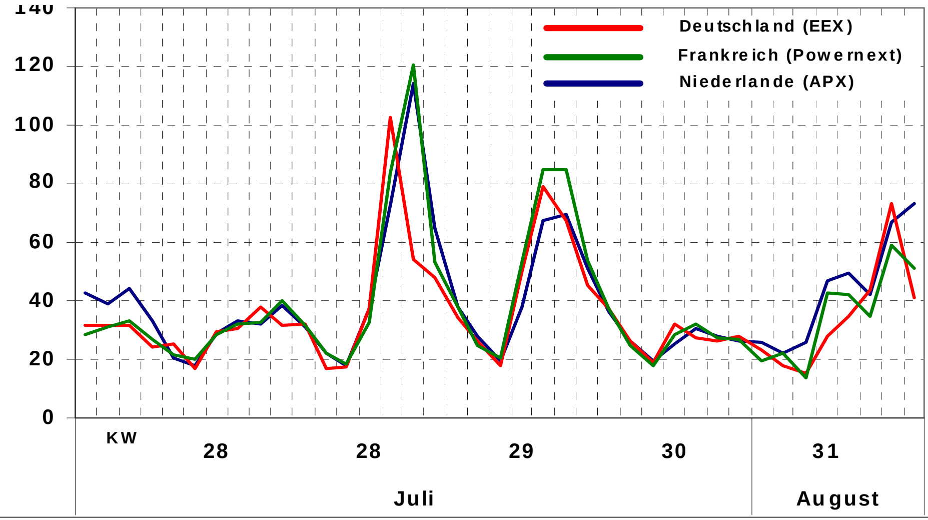
***d. Regulation versus "contestability"***

Creating an integrated transmission company is an appealing proposal because it ensures that there will be consistency between the ways new investments are managed for transmission or supply. However, the example of Italy shows that this condition is not sufficient to ensure that investments will be made in time with the appropriate trade-offs in terms of technology.

Transmission is a monopoly, but investing in transmission should be open to competition because, if it is not, there will be less pressure to invest in time and use of new technologies that might overcome some public or environmental constraints. Private actors are right when they say that recent capacity shortages in some developed countries could have been alleviated or avoided by creating competitive pressure and opening transmission investment to private merchant operators and new technologies. The TSO should not be in a position in which it can prevent or delay private investment decisions once they have been cleared for siting (e.g., environmental) purposes. It should be competition that drives such investments, not the preservation of a certain structure or market power.

Europe, with an average 7% interconnectivity, is far from being a single market even though spot prices in some national markets are similar. This is illustrated for periods of low demand in Graph III-1 in $/MWh for the summer of 2003. This situation, including the strong peaks at the end of July, will continue unless more lines, including DC lines, are constructed. In the European Union, where the objective of electricity market reform is to build a single market, the progressive harmonisation of the different national regulatory regimes will contribute to ease the transactions between non-adjacent countries.

**III-1: EUROPEAN ELECTRICITY SPOT PRICES ($/MWh)**




*Source: EPX*

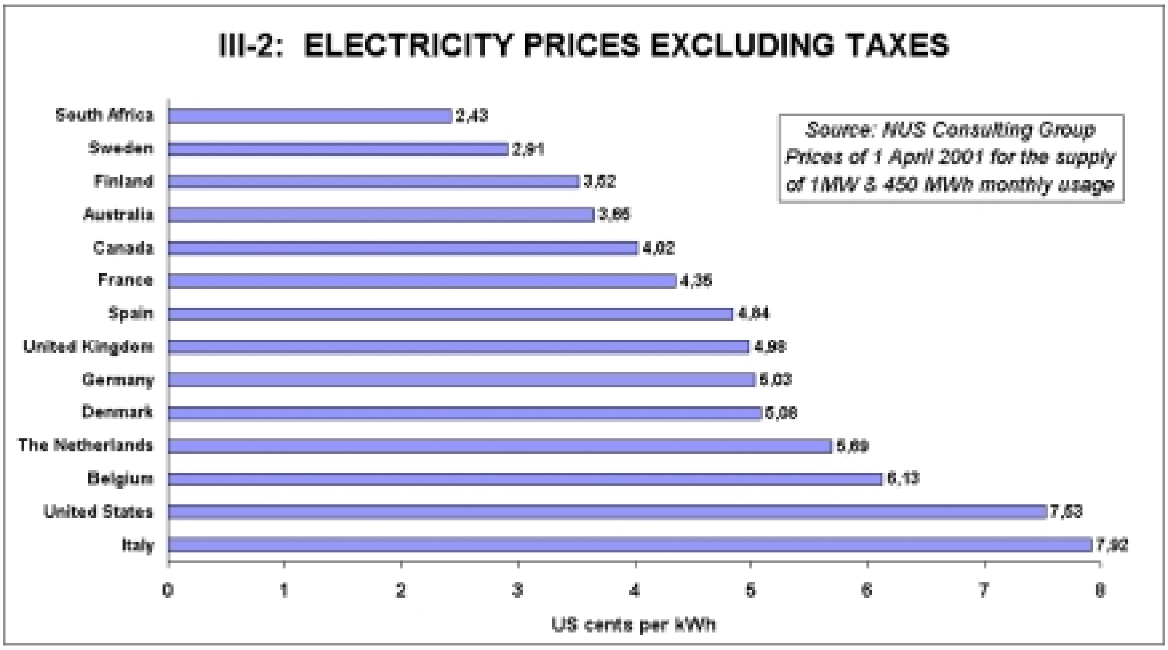
Given the importance of interconnections to make the market more competitive and secure, not only should transmission tariffs be carefully designed to bring the appropriate incentives to expand the grid and reduce congestion, in particular at national boundaries, but private actors should also be allowed to invest in their risks and benefits and choose the most efficient technologies, including DC lines.

The IEA chart in Part II (page 65) gives examples of how transmission is organised in OECD countries. Very few allow the TSO/RTO to be “contested” by new private entrants willing to build their own lines at their own risk if the operator is too slow or not innovative enough. Even in the three most favourable national contexts in this regard - Australia, New Zealand and Spain - it is unclear whether a private merchant can launch a line that is not deemed necessary by the TSO.

**3. Private or Public Power Generation?**

State-owned generation monopolies still exhibit remarkable successes in some countries. For instance, Norway seems to be comfortable with its municipally-owned distribution companies, EDF is considered a success in terms of management/costs of its nuclear plants and ESKOM, the national South African electricity monopoly, has the lowest electricity cost in the world. But private-owned competitive systems may also be extremely successful. For instance, Finland is not only among the countries with the lowest costs of electricity, but it will soon invest in a nuclear IPP with an announced levelised cost of three cents per kWh. Broad conclusions on the ownership of generation cannot be easily drawn.

Graph III-2 suggests that the national endowment in terms of diversified or cheap primary energy supplies may be a more important factor in the efficiency of generation than ownership. If a country is a net importer of energy services, the ownership of generation may require more attention than if it is not.




While privatisation for distribution is a first order question, market reformers need to reflect on whether the privatisation of generation should have priority and under what conditions. The answer has much to do with the governance, often more effective in the early stages of economic development in public hands than in private ones, if either enjoy de facto monopoly power because of the absence of a critical mass of companies or regional trade in energy services to ensure adequate competition. However, as this report has already noted, the five elements of good governance - integrity, quality of service, leadership/management, capital costs and manpower costs - evolve over time. The resistance to change tends to become entrenched at precisely the time when the increased complexity of energy markets requires more flexibility and more reliance on new technologies and management techniques.

A privatised monopoly with strong, appropriate regulation is perceived as better than a public monopoly where there is the risk that regulation is complacent and based on political motives. Regulation is less powerful than competition but over time, the initial "dissymmetry" of information between the regulator and the private firm disappears, allowing the regulator to squeeze the margins and benchmark the costs against other regions or sectors. This is what has happened in the USA, after many false starts which an immature developing country might not be able to afford.

A good indicator of the need for privatisation is the cost of manpower, especially in the distribution sector. In publicly-owned generation companies, guaranteed employment with a very low risk of being laid off and good salaries may initially reward integrity and quality of service, but at one time or another, over-staffing occurs, there is a smaller workload, more favourable pension schemes and golden-plated benefits. Usually, intransigent trade unions carrying much political clout are involved and rely on strikes and supply cuts to prevent changes. It is at such a point that government energy policy needs to ensure the "corporatisation" of the publicly-owned generation company or to envisage privatisation, unbundling and competition because, in a competitive system, the struggle for survival is the driver of change. There are those energy policy experts who believe that publicly-owned companies can operate on a fully commercial basis, while others would argue that the mix in the market of public and private companies is not sustainable:

- Even though the record shows that the state is a good shareholder in the early stage of building adequate generation capacity in a growing energy market, there is an inevitable worsening trend and, sooner or later, a need to rely on private initiative and competition. There is no rule carved in stone as to when or how such governance problems arise, but the most labour-intensive sectors in an economy tend to evolve the same way; in energy systems it is the distribution and generation stages which face this problem most acutely, although the investment problems in the Italian transmission system also highlight the phenomenon. When the performance of state-owned utilities is no longer satisfactory (and it is ultimately the government who must judge this), one needs to cut the large initial structure into smaller pieces and corporatise or privatise their activities, the more so for the sectors having the largest labour costs.

The success of France's EDF nuclear programme or South African's ESKOM cost performance are related to the low cost of capital they enjoy, which is an important factor for capital-intensive projects, and to the economies of scale achieved thanks to a series of plants with similar designs. However, the recent example of Finland suggests that it would be too bold to associate low generation costs with public ownership. In fact there are two different issues:

- First, base load plants with significant upfront capital costs like nuclear or hydro power may need special structures in which they are protected against the market risk because it is the only way to have access to cheap capital;
- Second, if economies of scale (possibly the case of French nuclear) or of scope (the integrated Brazilian hydro system) exist, the corresponding programmes should not be cut into pieces (whereas other plants, including coal-fired units, may be).

Such systems may be managed by a single buyer system, but one can also create ad hoc structures within which no competition exists but which participate in the competition indirectly and without distortion by selling their output as a set of "virtual generators":

- France is an example in a state ownership context; in order to get European Union approval of its purchase of German power company EnBW, EDF has auctioned rights to nuclear generating capacity as a way of increasing competition in the power market, but without selling nuclear power stations, which would have been politically unacceptable;
- Finland is an example in a private ownership context; the three main generating companies will launch a nuclear IPP that will be owned and operated by a "shell structure" which will

then sell the output at cost to its three shareholders. This supply will then be part of their portfolio or sold to third parties on competitive terms.

In this way, whatever the ownership of generation capacity, output or generating rights may be sold at cost to other suppliers under long-term contracts[38]. It may not be imperative to put transmission or generation under private ownership, especially if most of the manpower is outsourced, but the benefits of competition (even in the developing world) and the risks brought by monopolies encourage such market reforms. The following policy issues should be addressed:

- A minimum is to allow competition for transmission lines or new generation units by private merchant actors on the fringe of the system;
- This step may be broadened to a system in which the state keeps control of part of the generation, for example, the coal-fired plants in India;
- In pure policy terms, public ownership should be under close scrutiny and should only remain if it is necessary and does not lock in inefficiencies; and,
- Public ownership may make sense for "public good" plants, such as dams which are also used for irrigation and navigation purposes.

One might summarise the range of reforms related to privatisation as follows:

- *Distribution* should be split into smaller entities and privatised as discussed in Part I;
- *Transmission* is not labour-intensive (most civil engineering work is contracted) and may remain state-owned, providing that investment may be launched by merchant third parties;
- *Generation* is more ambiguous because high labour costs argue for privatisation, whereas economies of scale in hydro or nuclear power may justify special treatment.

**4. Loyal Competition or Market Power in Electricity Markets?**

Definition of Market Power

- ***"A firm is said to have market power when it acts in a manner that is intended to change market prices and can maintain prices at a non-competitive level for a significant period of time"*** (Sophie Meritet, assistant-professor, CGEMP, Paris IX Dauphine University)
- ***"A company has market power if it can move the market price by unilateral actions"*** (Graham Thomas, UK consultant to WEC Studies)

Competition does not work if market players are able to implement explicit or implicit cooperative strategies. Non-cooperative games are exemplified by the "prisoner dilemma", a university textbook example in which two men are caught in the close vicinity of a bank that has just been robbed. They are kept in isolated custody (to prevent them from talking to each other to agree on a common defence strategy). Each prisoner is then offered a choice - three years in jail on condition that he denounces his accomplice, but ten years if his accomplice denounces him. They also know that they will be freed if no one talks. The question is, what is each prisoner's best strategy? Convinced by the mini-max criteria (minimise the maximum pain for all outcomes), students usually suggest that each prisoner should admit his guilt. Not at all, is the professor's answer, for one cannot imagine that two men would rob a bank together without knowing and trusting each other.

The importance of cooperative attitudes, or "gaming", is emphasised by an extraordinary yet true example. During World War I on the Belgian front line, German and British trenches were very close, perhaps 100 or 200 meters apart. The army leadership noticed that no shooting happened

[38] The risk has not disappeared, but given that risk is associated with the variance of the expected returns, i.e., the square of the share retained by each party, then everything else being equal, three equal parts result in a risk nine times lower for each party.

when meals were distributed, as if there was a tacit agreement to stop firing those times. In reality, the cooperation was even greater, because if one man were shot by the other party during such truces, there was an implicitly agreed retaliation: two or three soldiers of the other party were consequently shot. Headquarters was much concerned and used all possible means to prevent this practice, including firing squads. A solution was finally found: the rotation of regiments every few months to avoid the development of such cooperative strategies.

**Privatisation in Energy/Utilities: a Disaster for Investors?**

***According to this text inspired by Professor Walde (University of Dundee), privatisation is needed but makes sense only if most of the capital can be raised domestically. This implies that a number of regulatory features should be enhanced, either in the broad institutional system (property rights, legal and financial rights, etc.) or in the energy regulatory system. In this respect, one way to improve the governance rules for utilities is to "regionalise" their exposure, that is, to create trans-national standards thanks to common financial and energy regional markets.***

In the 1990s, investors poured enormous amounts of money (often procured from private investors, pension or investment funds) into buying privatised utilities, mostly electricity and gas, and silly prices were paid. But this was not only or even primarily a developing country phenomenon. It was even more pronounced in developed countries such as UK, USA and Australia to name but a few where the overvaluations were the greatest. The developing country risk was introduced through higher discount rates, but the real issue for all countries was that assets were badly assessed because all investors totally failed to begin to imagine the regulatory risk, assuming, for instance, in the UK that the lax regulation at the time of privatisation would persist. This rush towards privatised utilities can be explained by the huge cash flows of the privatised and/or deregulated utilities and the bull market of the 1990s, which distorted judgments.

In Latin America, the prices paid were not so inflated, and no one foresaw the collapse of Argentina. In fact the privatisation of utilities in Argentina was a good thing, and the Argentinean currency collapse which occurred in late 2001 had nothing to do with the energy situation. In Brazil and elsewhere in Latin America, such as in Chile, Peru and Colombia, the experience has been broadly positive for the countries that received the proceeds from privatisation strategies such as those discussed earlier.

Investment disputes now abound, especially in Asia, where long-term contracts and IPP were heavily used and proved not to be robust against the declines in the currency. While currency problems have not been limited to developing countries, the legal systems in industrialised economies are more robust in dealing with such currency problems. In the UK, the windfall tax raised significant revenue; a similar type of action in Argentina would have caused an international storm because foreign investors have leverage (while in the UK they did not).

The interesting question is where investors may go next. There is an investment recession in the utility sectors and very little interest today in new investment in most parts of the developing world. How will the grand targets of the World Summit on Sustainable Development of Johannesburg be met against this background? It is unlikely that they will, at least not until another approach can be found that accesses expertise without requiring investment of foreign capital.

This question of funding, i.e., why privatisation in developing countries has been primarily funded by foreign capital and not by domestic capital, is not new but has become more acute in the present hard times. The answer is not a lack of potential capital but a lack of trust. A first reason is that foreign investors have leverage in developing countries whereas domestic investors do not. A second is that property rights are not always respected, nor are the rights to a fair and well-protected financial and banking system.

Competitive electricity markets are generally set by auctions every hour or half-hour and adjusted up to six consecutive times. If one adds additional ancillary markets for spinning capacity, reactive power, etc., one finds that market players meet hundreds of times a day. As with the British regiments in Belgium, it is unthinkable that cooperation does not develop, but, unlike the British regiments, one cannot rotate the “players” to introduce new faces to enhance competition. Sophisticated energy markets run the risk of remaining imperfect in the long run because they naturally lead to cooperation and market power. Perhaps the most prominent example today is the alleged gaming which operators in the California electricity market perpetrated in the 2000-2001 crisis period.

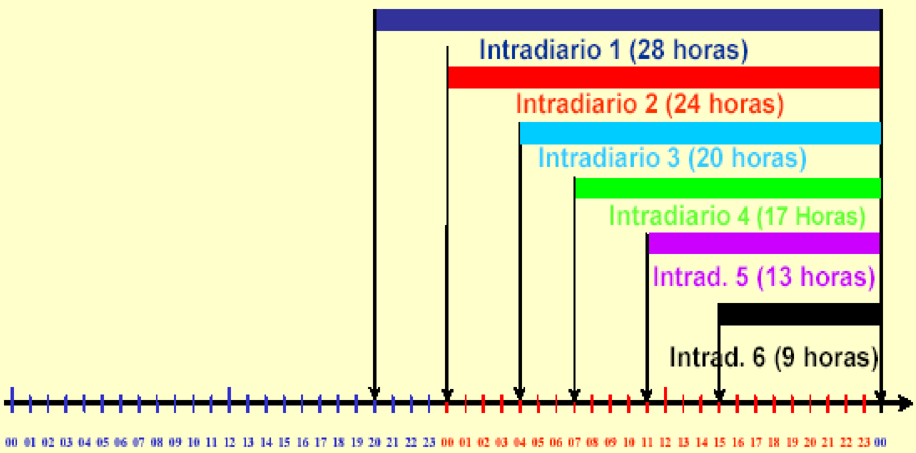
As shown in Graph III-3 related to the Spanish market, actors meet every half-hour or hour up to ten times a day (day-ahead market, six adjustment day markets, spinning capacity market and possibly black start capacity market) with 24 or 48 different hourly or half-hourly prices for each day. For instance, for a 23:00 slot in November 2002, the following prices were posted in Euro cents per KWh.

| | day | intra-day 1 | intra-day 2 | intra-day 3 | intra-day 4 | intra-day 5 | intra-day 6 | intra-day 7 |
|---|---|---|---|---|---|---|---|---|
| c€/kWh | 2.261 | 1.999 | 2.061 | 1.9 | 1.85 | 1.85 | 2.161 | 1.957 |

This complexity shows that many possibilities of arbitrage exist, each potentially giving birth to market power. One may note the great price volatility even in intra-day markets, which shows that the introduction of competition is difficult and requires discipline from the stakeholders because an error by one of the participants may signal disaster for all.

**III-3: HORARIO DEL MERCADO INTRADIARIO**

6 sesiones diarias




*Source: CRE*

Because the first competitive electricity market was established as a mandatory pool by England and Wales, some countries were tempted to follow the same model and adopted similar market designs without having in mind that market power is more likely to appear with this kind of design than with others.

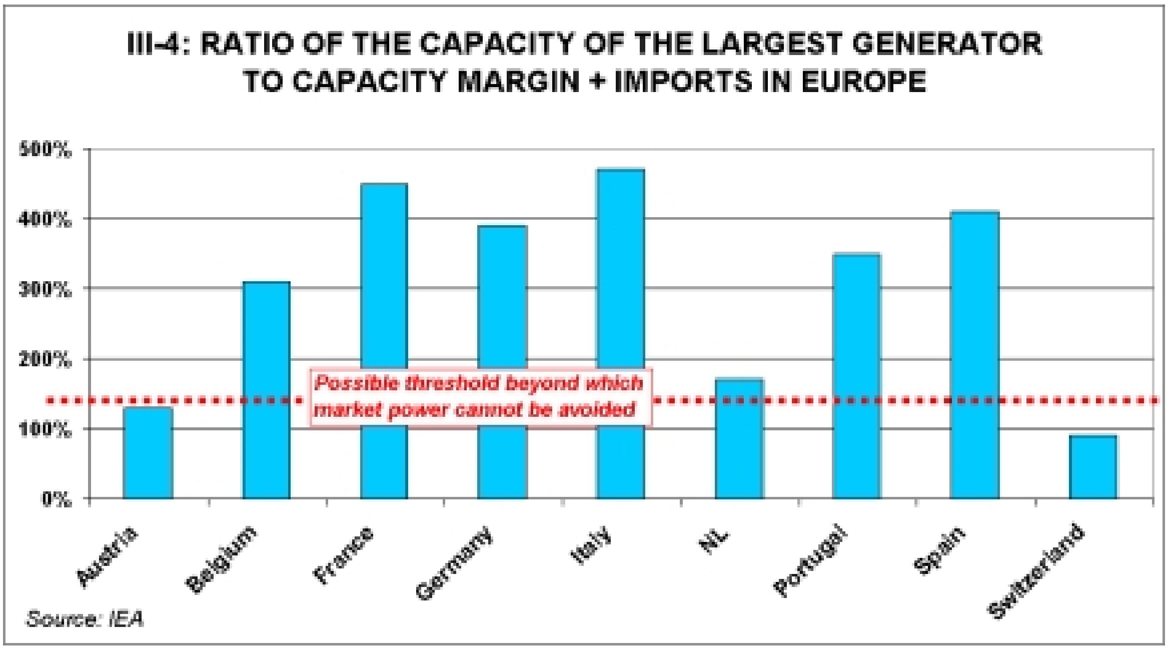
And no country has concluded so far that the only way to avoid this risk is to drastically reduce the number of auctions[39].

***a. The role of price elasticities***

For electricity and natural gas, short-term price elasticities of demand are small because most consumers have fixed tariffs and are not, therefore, sensitive to price variations. The overall short-term elasticity is about -0.10 (even though the comparison among countries with different price environments suggests that the long term price elasticity is much larger, possibly close to -1.0). This means that a generator has the ability to exercise market power with a 10% market share, a value generally much smaller than the market size of the incumbent companies. In addition, such dominance can be exacerbated by the small share of imports and/or the small domestic capacity margins.

To increase competition, one requires more actors of a certain size, therefore reducing the average size of all the actors in the market. A reasonable rule of thumb, given the small price elasticity of demand, is that no generator should control more than 10% of all capacity in the area of relevance, which is the region where competition can actually take place without being inhibited by transmission constraints. Other criteria exist, such as the ratio comparing the largest generator to the marginal capacity plus imports. Using this method, Graph III-4 shows the concentration of the electricity market in Europe. Another method is known as the Herfindahl-Hirschman (HH) index: a monopoly has an HH index of 1 and an atomistic market an HH index close to 0. With 10 actors having 10% market shares, the HH would be 10 times $0.1^2 = 0.1$.

Having more and smaller actors has a drawback, however, because they may not be able to achieve the same level of economies of scale; in fact, diseconomies grow quickly when the average size of the market actors is reduced. This calls for trade-offs and different market designs. The Netherlands has opted in favour of four similar-sized generating companies in spite of the small size of the national market, while in Germany, E.ON and RWE dominate the much larger German market thanks to a series of mergers and acquisitions.




[39] As discussed further in the text, one can imagine designs in which there is no short-term competitive wholesale market. It would be replaced by annual auctions in which each plant would bid what it guarantees in terms of availability (planned and random shutdowns), output (GW) and generating costs (based on fuel prices). Then, on the basis of the winning bids, the system operator would set the wholesale price on the basis of the merit order. This would ensure a cutthroat competition with no risk of gaming strategies because no market player would dare to cheat and then bear the risk of being left out of the market for one year. Such a system might be of interest for the developing countries willing to introduce some, but not spot competition.

***b. Dominance of the incumbents***

Meeting often on the same competitive market is analogous to the war situation described above and sooner or later will lead to some cooperation. No *explicit* agreement is needed because the communication is indirect. If player A notices that a certain action generally drives a certain kind of response from B, he will adapt. B will do the same. A further level of cooperation will be reached when “messages” about retaliatory actions are exchanged and agreed. For instance, if A stops playing the “game” according to the informal rules that have progressively emerged, B will punish him by adopting an antagonistic attitude. In short, market power can emerge spontaneously without any formal cheating.

As mentioned earlier, the dominance of a few generators is exacerbated in electricity markets that have little interconnection capacity with their neighbours, which is the situation in Western Europe, North America and other federal countries like Australia or India. The situation is even worse when, in addition to border bottlenecks, there is a high degree of geographical concentration.

In Europe, the five largest companies have 60% of the market, with respective shares of 19% (EDF), 13% (RWE after it acquired INNOGY, the former UK National Power), 12% (E.ON after it acquired POWERGEN in the UK), 8% (ENEL) and 6% (VATTENFALL); they are the leading actors in their national markets. Market power is endemic in the countries dominated by one (EDF in France, ENEL in Italy) or a few (Finland, Germany and Spain) dominant actors. In North America, similar situations exist with two clear examples, those of California and Texas (during the transition phase). Unidentified market power may exist in other states/regions of the USA, but to a lesser extent than in the rest of the world because of the long tradition of regulation and vigilance of the US Public Utility Commissions (PUCs).

Given this background, the four possibilities for dealing with market power in electricity systems are:

- To increase the number of players (a tactic easier to describe than to put into action[40]), thus limiting the risk of cooperation. This is what happened in the UK, where the duopoly of National Power and PowerGen progressively disappeared because of the increasing market shares of the new entrants, or what was imposed on the Californian utilities (PG&E, SOCAL and to a lesser extent SDG&E) or what has been imposed by the regulator on ENEL in Italy[41];
- To decrease the number of interactions by possibly suppressing the hourly markets and/or entering into long-term contracts, a solution seen as a compromise since it also reduces the short-term possibilities of switching to another supplier;
- To directly regulate the output of the incumbent utilities by constraining their wholesale bid prices within a range. The cap would kill any incentive to remove capacity, and the floor would avoid distress for new entrants. Unfortunately, unless the same price range is imposed on all generators, the system is unfair because the revenues of the incumbents are capped, whereas those of the other parties are not;
- To accept some “soft” market power, for example, that short-term spot prices not be fully competitive as long as long-term prices are. This situation happens in many countries and may be accepted by the regulator on the grounds of contestability, that is, when he knows that distorted prices will be undermined by the entry of new actors in the market. With this

[40] The experience shows that competition lowers prices to the extent that companies leave the market and concentration increases. This creates market power and leads to higher prices which attract new entrants along a cyclical boom-bust cycle.

[41] Italian power giant ENEL is required by Italy’s regulator to sell or rent out power stations to reduce its dominant market share. Even after ENEL has completed the sale of 15 GW of capacity under the ongoing liberalisation process, it would still control ~50% of Italian power production. The regulator also proposed temporary transfers via a formula of rent contracts or auctioning off annual production quotas according to a model of "virtual generators" already being tried in various countries (an approach also chosen by EDF to get European Union approval of its purchase of German power company EnBW).

kind of "soft" market power (as opposed to the "hard" market power that was exercised by PowerGen and National Power in the former England and Wales pool market), the resulting "market" is reasonably competitive (long-term prices do not create long-term rents), reasonably stable (there is less volatility than in pure competitive spot markets) and reasonably secure in terms of long-term supply.

***c. The story of market power***

In the early market designs, security of supply and diversification of supply were not priorities because of the large capacity margins for both electricity and natural gas. For electricity, this was the result of the heavy investments after the first oil shock in 1973 (to replace the former oil plants and to anticipate an economic growth similar to that of the 1960s and early 1970s). These designs failed to anticipate the slowdown in electricity demand, but the resulting imbalance was amplified by the new provisions favouring non-utility plants such as CHP. For natural gas, high prices encouraged increased supply while dampening demand, eventually amplifying the impact of the economic recession.

Thus not only was security of supply not a concern at the initial stages of energy market reform in the UK and the USA, but clearly, the purpose of market reforms was to lower prices in the face of over-capacities. Costs declined because of the cuts in the labour force of public utilities, privatised and otherwise, the decrease in fuel costs (especially oil and gas after the 1986 counter-shock with additional downward momentum for gas with the apparition of bubbles in the USA in 1986 and the UK in 1995) and the closure of many redundant old and expensive plants. The original concepts of energy market reform gestated in a time of cheap energy getting cheaper, and many politicians around the world made their cases for energy market reform on the grounds that consumer prices would decline.

In the UK, the first wave of CCGTs was built by the regional electricity companies (REC) just after the dismantling of CEGB because they still had a monopoly of supply for their captive customers and were allowed to produce up to 25% of their supply. Being producers and sellers, RECs had no risk and were ready to sign 20-year gas purchase agreements at 25 pence per therm and more ($3.8/MBtu and more). A second wave of CCGTs occurred after the RECs had lost their monopoly rights. Gas prices fell to twelve pence per therm ($1.5-1.8/MBtu) in 1995 thanks to the bursting of the gas bubble precisely when electricity prices were high because of the market power exercised by PowerGen and National Power.

The US also shows evidence of market power by the incumbent generating companies, either by the "gaming" over the different markets described above or in the creation of "niches" when interstate transmission capacity was tight. The most extreme example is that of California between June 2000 and spring 2001. This crisis is a textbook case on the consequences of creating an extremely costly and complex market design. After California came Texas during the 2001 pilot phase of its deregulation, with a reform model[42] which was supposed to be perfect. Six companies (AEP, Constellation Power Source, Mirant, Reliant Energy and TXU) were accused of "regulatory quirks".

It is clear that market power is "con-substantial" to spot-based competitive electricity markets, but in most case, such as in Spain, it is kept in check by the regulator or the self-discipline of the incumbents. In the case of France and Germany, there is no evidence of a strong abuse of market power that would have pushed the long-term equilibrium price up, in spite of the very large size of

[42] In this system, QSE (qualified scheduling entities), i.e. aggregators, must project a day ahead how much electricity their clients expect to acquire or generate on a given day. ERCOT (Energy Reliability Council of Texas) then pays money to QSEs that consume less energy than they project and imposes charges against QSEs that produce less energy than they project. Authorities analysed the forecasting behaviour of 45 QSEs during a 15-day period in August 2001:

- One company consistently missed its forecasts by 5% to 45%;
- Another by 150% to 300%;
- And a third by 75,000% to 400,000%.

the incumbent companies. This confirms that the threat of an intervention (e.g., the German cartel authority, the French regulator or the competition directorate of the European Commission) combined with the desire of the incumbents to avoid the entry of too many new actors actually limits the abuse of market power, its degree over time and the risk of distorted long term prices.

***d. Market power as a self-defeating strategy***

In the long run and under normal conditions, that is, for markets in which no barriers to entry exist, the quest for market power is a self-defeating strategy. The best example is that of England and Wales in the early 1990s when the duopoly created by PowerGen and National Power disappeared, not because of regulation but because of the entry of new companies which took market share. The counter-example of a "non-contestable market" is that of California, where it was impossible to build new plants because of NIMBY or BANANA.

In more recent situations, market power is also self-defeating in a more subtle way when the wholesale electricity price is kept very close to the LRMC by the incumbent utilities. Such a price would be on average roughly what it would be if no market power were exercised. It is high enough to justify the building of new power plants but low enough to attract investment in such new plants only by the large incumbents; the additional risks faced by new entrants would not be covered. Hence this subtle form of market power smoothes the otherwise wild oscillations of the commodity market and maintains the market shares of the incumbents. It may also trigger sufficient capacity in time to provide long-term security.

Should one live with market power? Some degree of market power is not bad *per se* if the market is truly contestable, that is, open to new entrants wherever they decide to operate. Market power becomes critical when the safety valve of contestability does not exist, a situation encountered when transmission bottlenecks isolate market niches or when investment in new capacity is constrained by exogenous factors such as the environmental review process. However, it must be remembered that even small levels of market power may impact consumers in two different ways, either by raising short-term prices to levels that penalise energy-intensive industries, making them uncompetitive in world markets, or by hurting the poorest captive users who cannot afford the higher prices over a sustained period.

It is a paradox to reform a publicly-owned monopoly by creating a competitive market only to find that competition does not work and degenerates into an oligopoly with significant market power. This is a dynamic of energy market reform that was not well understood even five years ago but has become central to the debate today. While market power has a positive side because it may justify new capacity investment early enough and avoid the long commodity cycle of over/under-capacity situations with their corresponding wild price variations, its shortcoming is that at best, it brings new incumbent plant investment but not a level of diversification among the players in the market or among fuel sources on which sustainable energy systems depend in the long run.

Extensive analyses and examples of market power are available in the WEC report *Electricity Market Design and Creation in Asia Pacific*. Contrary to many opinions, market power can exist with as many as five different generators, whereas competition theory suggests that this number should be sufficient in most markets. The already mentioned reason for this particular feature is that most consumers receive energy at fixed tariffs and therefore are indifferent to real prices at the wholesale level.

The more electricity markets rely on spot mechanisms, the likelier it is that cooperative behaviour, however implicit, will occur, especially in periods of reduced capacity margin. However, good regulation combined with incumbent cautiousness can reduce the "imperfections" of the market. In addition, these imperfections can be further reduced by relying on long-term bilateral contracts and limiting the spot market to a random balancing mechanism only used to settle the unanticipated contract differences "at the margin".

Prices are higher in the monopolised gas markets because consumers pay gas on the basis of its "value", that is, the cost of the potential competitor such as electricity for cooking, fuel oil for heating, heavy fuel oil for power plant or large industrial boilers. Once competition has been established in the gas market, all prices are set at the margin, generally related to the heavy fuel oil price (as shown earlier in this Report) with differences reflecting the cost of transportation. For this reason, market power in the natural gas market is possible only if all customers become captive, that is, if interruptible industrial users or power plants have disappeared. This needs to be avoided to keep the natural gas market competitive.

**5. The Momentum towards Competitive Wholesale Markets**

Market reforms reflect a change of philosophy more than a change in the conditions prevailing in many markets, in particular, in the USA after the two oil shocks in the 1970s. The embrace of liberalism in some countries is attributable to the belief that markets produce conditions that are socially and economically beneficial. Also influential is the pragmatic argument that market-based economies have been doing much better than other types lately. Specifically, there is a general perception that the economic performance of the UK and USA has improved since they began emphasising liberalisation in a number of sectors. Free-market advocates maintain that the experience of the 1980s and 1990s conclusively shows liberalism is superior to alternatives such as socialism, communism and state-led capitalism.

The question remains, however, as to whether liberalism is the right word when it comes to energy market reform. As shown in earlier parts of this report, electricity is not a commodity just like any other; it cannot be stored, and when the price goes up or the lights go out, the government hears about it and, more often than not, feels compelled to intervene. Appropriate regulation is the other side of the energy market reform coin; even the word "deregulation" has fallen into disfavour as an accurate description of what energy market reform is all about.

With these important qualifications in mind, the drive towards liberalism was first applied to competition in wholesale electricity and natural gas markets. However, through the 1990s, experiments here and there have created growing concerns on the ability of the pool and balancing market designs to deliver what a country needs. The next decade will see more development in energy service trading to achieve better market results or a move to more comprehensive government energy policies which also cover the trust, social and environmental goals it sets for the economy as a whole. To date, the benefits from most energy market reforms have not always flowed to the end-user. Diversification, security of supply and lowest sustainable prices are more likely to result from comprehensive energy policies that use a combination of market and regulatory features with the focus on delivering specific objectives than from the purely competitive spot wholesale markets created so far [43].

A metaphor was used by FERC Chairman Pat Wood III during his August 2001 interview which appeared in *California Energy Market*s. Wood did not back off from FERC's policies to advance competitive energy markets but said he believed problems like those faced by California will not resolve themselves without regulatory assistance. He said, "Markets are not born fully mature. They're born as teenagers. They go out and drive too fast and drink alcohol. When people start getting hurt that's a sign the market is immature". He pledged that FERC will help guide the USA electricity and gas markets towards maturity. In his view, one goal for regulators is "getting smarter than the industry".

[43] A particularly pessimistic view is that of Graham Thomas, consultant to the WEC study group, who coordinated the WEC report *Electricity Market design and Creation in Asia Pacific;* he is sceptical about the ability of further "market freedom" to deliver the needs of many countries. Developed countries may be able to afford the cost of further experiments but developing countries cannot.

Whether the metaphor is relevant or not, indeed, whether regulatory authorities can be smarter than the industry they control, are questions that might be answered negatively by some observers of energy market reform in specific countries because regulators have access only to dissymmetric and patchy information. Regulators often do not have the same budgets or incentives that energy companies willingly put into their cases for sound financial reasons. The starting point of market reforms is often characterized by unfavourable conditions such as the existence of dominant incumbents, merger waves, inadequate interconnections for electricity transmission or gas transportation and non-liquid or absent wholesale markets.

Remembering that market power, expressed as the ability to raise peak prices, is inversely related to the number of generating companies (often small because of the size of incumbents or the transmission constraints that fragment the market) and to the price elasticity of demand (always very small in spite of a theoretical value close to 1 because very few customers get variable price signals and most have constant tariffs), one can understand why the situation of true competition is rarely encountered, except when there is a substantial capacity margin and many generators in the market.

However, even though the presence of a large idle capacity margin is more prone to competition and low prices, as demonstrated by the decline of wholesale prices when markets exhibiting this kind of feature were opened to competition, such as in the UK, it is an unsustainable situation in the dynamic perspective of a growing market because low prices set on short-run marginal costs discourage entry and the generators may fear price caps when the capacity margin begins to shrink and prices rise.

If one observes the implementation results and status of energy market reforms so far, it can be said that:

- The UK has implemented a design over fifteen years and changed it substantially as it went along;
- California chose a sophisticated design, only to realise within two years that policy and regulatory mistakes had been made, causing enormous losses to consumers and to companies;
- Some countries have set up the program of reforms, but part way into it, have postponed the process or changed the rules;
- A few other countries or regions, such as those in the European Union or some parts of North America, South America, and now India and Brazil, are still moving forward; and,
- All countries will always be under pressure to enhance their energy trading mechanism and to establish incentives for their power balancing system at the national or regional level in order to maintain security and reliability of supply.

This variety of situations shows that there is certainly no unique model of energy market reform that should be prescribed and that specific national or regional circumstances have to be taken into account such as:

- The political culture of the country in terms of open markets or a planned economy;
- The very different institutional infrastructure supporting reforms in developing versus developed countries;
- The indigenous energy resources of the country versus the need for imports;
- The size of the indigenous energy market and the systems needed to support it;
- The special concerns of relatively isolated markets (such as Japan, New Zealand, Australia) versus groups of countries in the same regional setting (such as the European Union or NAFTA);
- The priority to be given to large investments by large companies versus local consumer service;
- The volume and nature of the financial requirements including the role of domestic savings.

Based on these observations and on the need to provide long-term security, two sets of market designs may be envisaged: those under the generic name of "single buyer" relying on a central operator with competition "at the margin" and those under the generic name of "competitive wholesale markets" where competition is a central feature.

***a. Single buyer systems***

These models are well adapted to relatively small markets and countries seeking the benefits of simplicity. They incorporate an explicit long-term planning and investment function to set the amount of capacity needed, the type and the location. For each new plant to be built, minimum technical standards are imposed and the best bid is chosen on the basis of the lowest levelised annual fixed costs meeting the imposed specifications. Once the plants are built and on stream, their use may be controlled by another, annual bidding process in which plants guarantee a certain availability and output.

The details can be adapted to specific circumstances. The idea is that the actual over/under performances above/below the target set at the construction stage of the new plant would be rewarded/paid at the wholesale price if they were anticipated, but unplanned differences would bear a penalty, for example, by being only partly rewarded in case of excess supply or by bearing a cost greater than the wholesale price for unanticipated under-deliveries. This would provide strong incentives for the owners to make sure the plants are available during the peaking periods[44] and to improve the output and efficiency beyond the threshold set at the time of the construction.

A single buyer system can also easily accommodate the stranded costs or the rents. Stranded costs would not exist *per se* since, once the construction bid has been won, the fixed costs, whatever they are as compared to other power units, would be paid annually on the basis of the amount defined in the bid. Rents could exist when a plant has come to the end of the contractual period during which it was supposed to recover its capital costs. Then the owner could be allowed to continue to exploit the plant without receiving any more capacity payments (but it would be in his interest to maintain the plant as well as possible) or the plant, such as a hydro dam, could be returned to the state before being again proposed on auction.

This system does not generate prices directly as in a competitive pool but relies on two set of costs: the capacity payments and the variable costs set for each individual plant depending on its specific characteristics. The capacity payments may be very low for amortised plants (e.g., re-auctioned hydro plants) or very high for new plants but will not necessarily be charged as such if the tariff is set on the LRMC and the difference[45] between actual costs and prices is returned to, or paid by, the government. Variable costs would be used to set the merit order.

"Single buyer" systems have two drawbacks:

- First and foremost, the operator of the single buyer system has no real incentive to increase efficiency because of its monopoly situation. As he will be mostly judged on the workings of the system, the single buyer may systematically privilege security against efficiency;
- Second, this system cannot work for large countries or regions like the USA, Europe, Russia, or China. One has to either create sub-regional single buyers with exchanges across the boundaries or rely on a competitive market with long-term contracts and spot residual market(s).

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[44] This is a standard procedure in competitive markets. The ability of generators to determine their outage times is covered by the "grid code" managed by the system operator, with the idea of having maximum margin during the peak periods.
[45] For instance the water "rent" of a dam is a public good to be used in the general budget but not given to the users. The same holds for stranded costs, preferably to be paid by the government budget to avoid distorted tariffs.

***b. Long-term contracts and "insurance" mechanisms***

The starting point for this model is that competitive markets, in the absence of market power, provide the commodity at the best price but do not necessarily provide a second indispensable good: security of supply. How does one establish a second competitive market that would superimpose the commodity market to provide security of supply at the lowest cost thanks to competition and, by the same token, to reduce the risk of market power?

The answer is not a capacity market because this is too limited a concept that focuses on capacity without taking into account other important aspects such as the diversification of plants and supply sources, the combination of different users who have different needs (e.g., interruptible users) and the resilience of the system. As shown earlier in this report, a capacity market is an "ad hoc" approach that works in the short term but may not be sustainable in the long run. For instance, if incentives to create new plants are only given to those who construct them, this creates a distortion between those who receive and those who do not receive capacity payments.

The reliance on competitive market mechanisms akin to insurance is a very appealing alternative but faces a number of practical limitations or difficulties. Insurance or other derived models, such as penalties in the case of non-delivery, require contracts long enough to cover the building of new plants. There is nothing surprising in such a condition, which has existed for decades for the setting of new gas infrastructures in the USA[46]. However, some experts do not accept this idea because such long-term contracts lock the two parties in and prevent a buyer from changing its supplier, thus keeping him with the same supply contract, possibly unfair in unforeseen circumstances.

In particular, long-term contracts can undermine retail competition by either preventing it or making it costly and difficult. Because of the extra costs incurred by LDCs to provide security on behalf of its captive customers, they may be prevented from changing their supplier or have to reimburse this extra cost. Furthermore, even if long-term contracts may be beneficial once competition exists, they may be unfair if signed before the launching of competition.

In a nutshell, the choice of a design for wholesale electricity competition depends on many different factors:

- The way distribution and retail supply will be addressed;
- The mechanisms by which long-term security will be provided; and
- The desired degree of competition for generation and supply.

There are no perfect solutions, only good trade-offs that depend on national/ regional circumstances and need to be worked out in that context.

## 6. Can Competitive Markets Accommodate Other Public Policies Without Too Much Distortion?

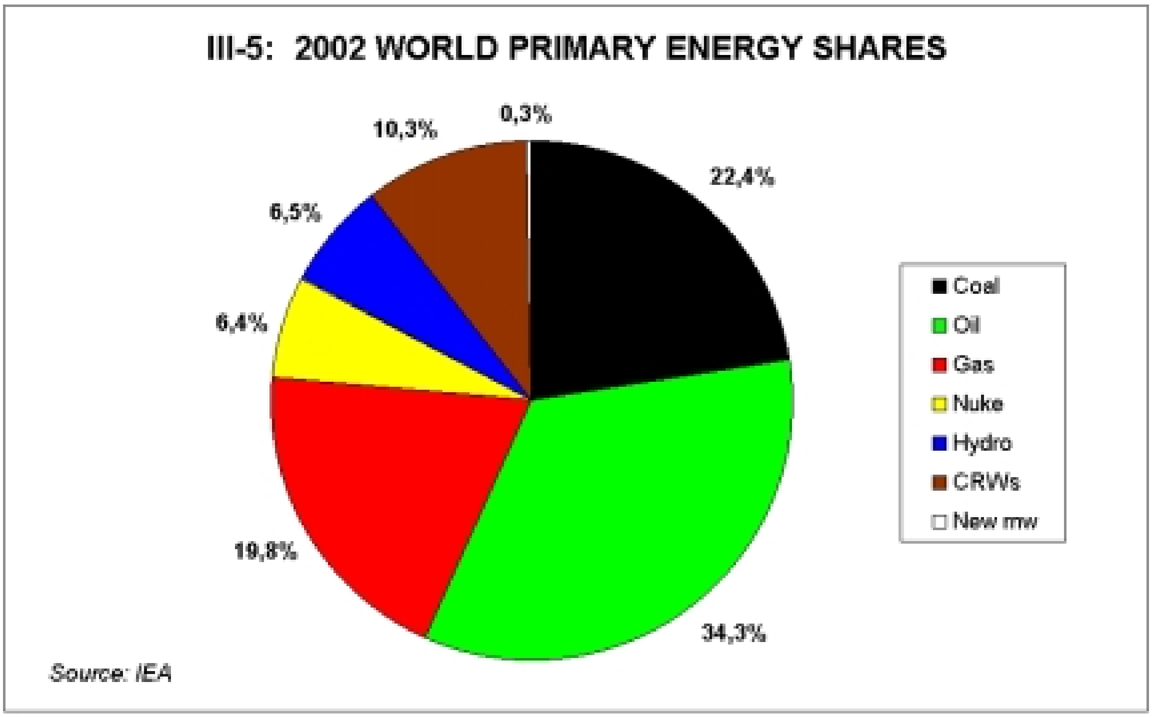
Policy goals cover a wide range of different issues. Some are hardly discussed because they exist in all countries and are taken for granted, such as the administrative processes for setting a new infrastructure or the legal rules imposed on the sector to cover safety, technical standards, financial or prudential rules. However, four issues are specific to the energy sector and the way reforms are implemented:

[46] In the USA, no building of a new pipeline or, up to the recent changes introduced by FERC, of new LNG terminals was possible before going to an open season, a process combining competition among the potential users and a long term commitment.

- The first and most important issue is the security of supply in competitive markets – long term capacity adequacy, short term reliability, diversification and resilience – and how this can be guaranteed;
- The second issue relates to the "universal" electricity supply with special funds available to LDCs to support investment for connecting remote customers, or ad hoc payments aimed at providing affordable and adequate energy services for the poor (special meters, vouchers, subsidies, etc.);
- The third issue is organising the transition to a privately-owned competitive market [47] with the definition and the means to pay for the stranded costs (including the social costs because of lay-offs); and,
- The fourth is the mandatory use of "renewable energies" as a means to reduce the amount of fossil fuels used to generate electricity and their corresponding GHG emissions.

***a. Renewable energies and market reform***

The first three of these policy issues are well covered earlier in this report or will be treated in Part IV. Let us focus now on the fourth issue of mandatory use of renewable energies insofar as it impacts energy market reforms.




Expressed in terms of total primary energy requirements, Graph III-5 shows that new modern renewable energies (such as wind, biomass, geothermal, solar and small hydro) account for only 0.3% of the 2000 global energy supply (10 Gtoe) but have been growing quickly (~10% per annum). Large hydro is of course a renewable too and accounts for a much larger contribution of 6.5% to the global energy supply but it is now growing at a slower rate of 2.7% per annum. The "traditional" fuels, including combustible renewables and wastes (CRW) mostly used in developing countries, account for an even larger contribution to the global energy supply (about 11%) but have the slowest growth of 1.5% per annum among all renewables.

[47] An imperative that governments should accept before changing what exists, especially when it works well, is to propose a back-up plan in case the market fails to deliver. This would certainly smooth the transition, because a little bit of strategic thinking prior to the decision would probably avoid ex-post short term unexpected and costly intervention by government.

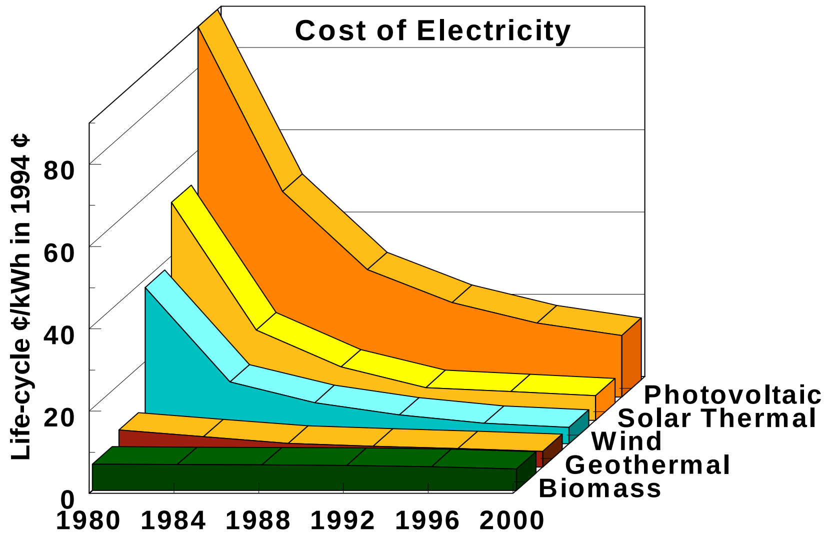
In the electricity sector, where most new modern renewables are used, they only represent 0.6% of the total world electricity supply and are dominated by wind with 30.7 GW of capacity at the world level at the end of 2002, mostly in the developed OECD countries (also known as "Annex 1" countries under the Kyoto Protocol), with respectively 22.6 GW in Europe, 4.9 GW in North America and 2.5 GW in Asia Pacific). Wind is the preferred choice, because, in spite of its intermittent nature, it exhibits the lowest costs and the best cost decline curve, recently enhanced by the development of offshore wind that offers much higher availability rates (up to 50% instead of ~20% onshore).

Graph III-6 shows that, while these new sources are not yet fully economic, their costs are falling rapidly, and governments hope that their subsidised introduction will accelerate economies of scale and technical breakthroughs that may allow them, some time in the future, to be fully competitive with other energy sources. Even North Sea offshore wind is still very costly, more so if one includes both the direct and associated environmental (GHG emissions) costs of back-up as well as the ancillary services and additional transmission charges. Many governments have set ambitious targets for renewables as a share of electricity generation, especially in Europe, but they now realise to what extent such policies can be expensive or impact unexpectedly on their objectives for energy market reform.[48]

In west Denmark, for example, consumption varies between 1,500 and 3,500 MW, and the installed capacity is made up of:

- Condensing central power plants: 1,800 MW
- Co-generation central power plants: 1,200 MW
- Local co-generation plants: 1,500 MW
- Wind: 2,200 MW

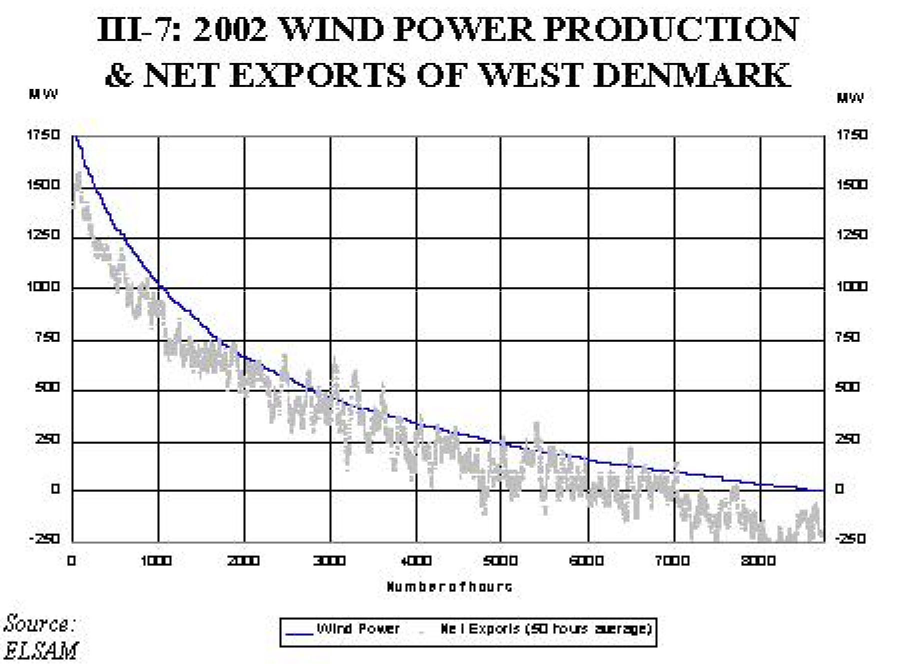
**III-6: COST DECLINES OF NEW RENEWABLES**




*Source: World Bank*

The total of 6,700 MW is higher than the peak demand even if one takes into account the actual availability rate. The electrical interconnections with neighbour countries are 1000 MW with Norway, 600 MW with Sweden and 1,200 MW with Germany (there are no interconnections with east Denmark).

[48] WEC Statement 2003 presents its views on the policy, economic and technical aspects of renewable energy targets, including the need for back-up and the impact on the efficiency of base load fossil fuel plants.




Source:
ELSAM

Graph III-7 shows the tight correlation between the availability of wind power in west Denmark and the need to export, mostly to Norway. The reason of this correlation is the lack of flexibility to run the domestic fossil-fuelled plants. All of them are used as CHP (cogeneration of heat and power) and cannot be stopped. The situation is worsened by the prohibition against using electrical heating in homes. Hence the supply of wind electricity is always in excess of requirements but is not usable, so it has to be exported.

Unfortunately, as one might expect, this excess production lowers the price (domestic and Nordpool), more so when bottlenecks appear. Prices are more or less inversely correlated to the exports and fall from ~400 DKK/MWh when exports are marginal (say less than 100 MW of wind), down to ~200 DKK/MWh when exports are greater than 1,000 MW. Hence not only is wind expensive and heavily subsided in Denmark, but its contribution to the overall economy is also negative; the revenues of west Denmark are lower when wind is blowing than when wind does not blow at all!

If these were the only impacts of Denmark's decision to promote wind energy, one could address them in a narrow government policy context. However, wind electricity requires Denmark to reinforce the transmission grid, a significant cost according to the regulator. Also, again according to the regulator, the network could not accommodate the ups and downs of its intermittent supply beyond a 5% market share if west Denmark were not integrated into the larger Nordpool market. This in turn leads to wind energy policy in Denmark lowering the pool prices in Scandinavia as a whole. This could be seen as an advantage by consumers if such a decline were not, literally, at their own expense, both in terms of subsidies supported by their taxes and the disincentive to launch investments in new baseload power plants needed for long-term security, which also impacts on neighbours like Norway.

The question arises as to whether it is possible to make government policy in favour of renewable energies consistent with a competitive electricity market. There are three possible approaches:

- The first generic approach is to set a proposed price and let market shares adjust;
- The second generic approach is to set the market share (quotas) and let prices adjust;
- The third is a hybrid approach combining both quotas and price floors and ceilings.

In all cases, efficiency gains should be passed to the consumers thanks to lower prices. For instance, the proposed Danish approach of tradeable green certificates (TGC) is a hybrid system. It calls for tradeable green certificates that will reflect the highest cost of green electricity but is subject to a ceiling aimed at capping the subsidy and to a floor aimed at guaranteeing a minimum subsidy over time. The advantage is that, within this "collar", producers will receive the spot price of the market, a price that reflects the intermittency (and necessary back-up) and the need to export electricity when the wind blows. The drawbacks are the accounting complexity and the possible lack of incentives for incumbent green generators.

It is up to the policy decision-makers in governments to decide what should be done in terms of social, environmental, or other policies. The regulator does not set this policy but must design systems that meet the objectives and tell his political masters what the related costs are (in terms of direct or indirect subsidies and lesser efficiency) in comparison with the benefits of the reforms. This is why:

- Costs of renewables should be established and should include a neutral estimate[49] of both the direct and the indirect costs (back-up, additional transmission and environmental[50] costs) for all envisaged options and not only those related to GHG emissions reductions. Renewable energies should be viewed first and foremost in energy policy terms;[51]
- End-users should be "empowered" by knowing what the full costs of different choices because, ultimately, it is they who will pay these costs.

**7. Summary of Part III: Wholesale Market Design**

Alison Silverstein of FERC in the USA has said, "Bad market rules are worse than no market". One cannot just let markets work. There must be constant vigilance by the regulator and the right tools to detect and remedy any market abuses. This is tricky because the borderline is very thin between a situation of genuine scarcity and a player gaming with transmission capacity or deliberately withholding power generation capacity.

The trouble is that there is no obvious optimum design for wholesale electricity competition, and trade offs need to be made. There are four issues to address:

- Ownership and unbundling in the upstream and midstream sectors;
- The natural emergence of market power in spot electricity markets;
- Market reforms and competitive wholesale markets; and,
- Accommodating public policies in a competitive market.

[49] According to Danish "Greens", the cost of North Sea offshore wind could be as low as € 6 cents per kWh but this figure is not accepted by most other experts. Another indication stems from the announcement by the UK government, on 14 July 2003, of a second round of leasing for offshore wind farm sites. The imputed cost of offshore wind output from these sites, at least until 2010, is estimated at £80-85/MWh. This is about € 12 cents per kWh, twice the optimistic Danish estimate and a premium of 350% over the current non-renewable forward wholesale electricity price for 2004.
[50] In their paper,"Balancing Fluctuating Wind Energy with Fossil Power Stations", W. Leonhard and K. Muller (CIGRE Autumn 2002) say, "Results show that even at this low penetration of wind energy, the infeed causes a hidden increase in the specific fuel consumption in remote fossil generating stations which produce less electrical energy but with higher fuel consumption and $CO_2$ emissions per KWh".
[51] In its White Paper on Energy Policy the UK government is returning to a policy of picking technology winners as evidenced by the direct financial support (investment capital subsidy) directed towards offshore wind projects as part of its GHG emissions reduction strategy. In so doing, it has ignored alternative conventional (e.g. CCGT and nuclear) or renewable generating technologies that could also contribute to reduce GHG emissions and meet UK commitments under the Kyoto Protocol at lower cost. This policy is being debated in the context of the UK becoming a net importer of energy by about 2006!

*Privatisation and unbundling* are touchy matters. Privatisation may go against the entrenched interests of the workers in state-owned companies but is increasingly needed because of governance problems. Large nuclear or hydro programmes may in certain circumstances need to remain in public hands, but such exceptions need to be transparently treated and periodically reviewed. Unbundling is at the heart of competition and the benefits it brings. However, it imposes the obligation on the regulator to ensure that there will be no gap in the supply responsibility chain.

*The threat of market power* is con-substantial to pool or residual balancing systems as the theory and empirical evidence show. Such potential power may ease long-term security concerns but needs to be tightly controlled and “contestable” in the sense that new entrants may freely invest. A greater reliance on smart meters (that make users sensitive to prices) and/or the drastic reduction of the number of bids may be used to alleviate this risk. Another approach may be to split the large incumbents into smaller “virtual generators”, but this has a limit because large regional companies are needed to bring financial, managerial and technological capacity, together with strong economies of scale, that would not otherwise exist. The regional integration of energy markets also plays a big role in addressing both security of supply and market power, with the added benefit that it helps “regulate the regulator” by establishing agreements and standards which are difficult to change for a solely national political purpose.

*Simple market design* should initially be preferred initially because sophisticated designs are costly, create regulatory uncertainty and risks and open doors to market power. For the developing countries, where national and regional circumstances play a key role, the choice of a design will be that of simple trade-offs. In the developed markets, where the design has already been chosen, simple rules are needed to ensure that there is no responsibility gap in the chain of supply and to prevent or limit market power.

*Public policies for social or environmental purposes* linked to the provision of energy services may be necessary and attractive. However, if the real costs are hidden, this creates the risk that governments may skew technology choices or pricing in ways which undermine the key objectives of energy market reform. Competition is good for the environment because it helps accelerate efficiency and the introduction of clean technologies, but only if the full and real costs of energy production, transmission distribution and utilisation are known and paid by the customer.

## PART IV: TARIFF-SETTING AND ENERGY POVERTY

The main theme of this report is that energy market reforms are for the benefit of the consumers, in particular for the residential and commercial sectors which face higher electricity and natural gas prices because of the additional cost of distribution. In the residential sector, the poor deserve special attention.

Energy poverty comes in various forms. While brownouts and blackouts in developed countries happen from time to time at great cost to their economies, these countries have choices, and their economies have the strength to adapt. These countries account for 20% of the world's population but consume about 80% of total energy supply. When it comes to real poverty, it is the two billion people in the world without any access to commercial energy of any sort who are the true energy poor; they reside mostly in rural areas in developing countries , unconnected to the grid, making do with highly polluting forms of traditional biomass often collected by women and children in daily walks of many kilometres for long hours. Another two billion people in developing countries have sporadic and unreliable supplies of electricity. This 80% of the world's population consumes only 20% of the total energy supply.

Tariff-setting matters to all households in the world, but it matters most to the world's poor who can never hope to break out of their poverty without affordable commercial energy services.[52] At the 18th World Energy Congress in Buenos Aires in October 2001, WEC concluded that energy accessibility goes to the heart of security of energy supply, not just in producing countries but in the whole transmission and distribution chain.[53]

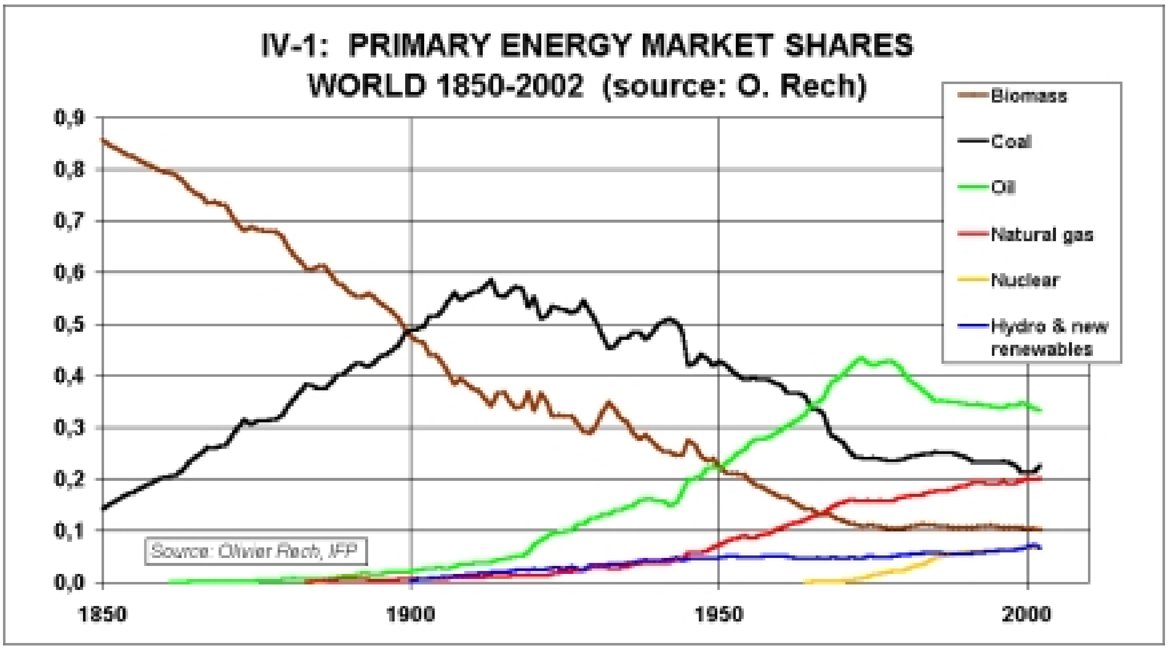
Four issues related to tariff-setting and energy poverty need to be addressed:

- The stakes of energy access in terms of economic development;
- The structure of tariffs, how they track the load and their impact on demand;
- The policies of subsidising or cross-subsidising consumption in the name of national interest;
- The possible ways to ensure affordable and sustainable energy access to the poor.

### 1. Energy Access and Economic Development

Worrying about the poor may seem to be only a moral imperative of no specific relevance for industry, but the reality is that a minimum of social equity within a country and among countries is also an economic imperative to ensure stable, peaceful and sustainable growth. In the energy sector, equity means providing access to those who do not have it and maintaining or improving access for those who face unreliable service or energy costs which are too great a share of their revenues.

[52] WEC participated with UNDP and UNDESA in the *World Energy Assessment* published in 2000 which covers the issue of energy poverty and was used as the basis of the energy discussions at the World Summit on Sustainable Energy Development in Johannesburg in 2002.
[53] See the Conclusions and Recommendations of this Congress at www.worldenergy.org "Energy for People, Energy for Peace".




Graph IV-1 shows that energy access remains a problem and has not improved for the last 30 years. The share of biomass (mostly "traditional energies", i.e., combustible renewables and wastes used by the poorest consumers in developing countries) had continuously declined since the beginning of the industrial revolution but has remained stable since the first oil shock in 1973; globally speaking, energy access is not improving anymore. As this trend coincides with the rapid urbanisation of the developing countries, energy access is progressively shifting from a rural (examined in former WEC studies) to an urban problem relating to the use and extension of energy networks. It is for this reason that energy market reforms are a central issue in addressing energy poverty today.

The imbalance between the haves and have-nots was mentioned in the WEC Millennium statement, *Energy for Tomorrow's World—Acting Now*! (ETWAN). The two billion poorest people have an annual income of less than $1,000 (current PPP dollars) and consume only 0.2 toe/y per capita, mostly as biomass, 25 times less than the 5 toe per capita in industrialised countries, mostly as modern energy. Moreover, the dispersion of individual energy consumption within countries is widening.

Electricity use is not the only criterion for assessing access, but the figures are frightening. The world electricity production was ~15,000 TWh in 2000 split into:

- 9,000 TWh for the developed market economies (800 million people),
- 1,700 TWh for CIS-CEE (400 million people),
- 1,300 TWh for China (1.3 billion people),
- 3,000 TWh for the other developing countries (3.5 billion people)

Thus the 1.2 billion people of industrialized countries use 10,700 TWh (9,000 kWh/year/capita) while the 4.8 billion people in developing countries only use 4,300 TWh (900 kWh/year/capita, 10 times less) with one out of three persons (1.6 billion persons) having no access whatsoever.

What would be the cost of providing modern energy services to the 1.6 billion people without access today, as well as to the 0.4 billion who will be added between now and 2020, mostly in developing countries? Delivering a minimum of 1,000 kWh per capita in 2020 (the 500 kWh per person indicative target that ETWAN suggested for today adjusted for twenty years hence) to the two billion poor people translates into an additional yearly electricity demand of 2,000 TWh, calling for 400 GW of new installed capacity at a possible total investment cost (for generation, transmission and distribution) on the order of $2 trillion over twenty years. That is $100 billion per annum.

This figure may seem enormous but is less than the $9.3T of capital in developing countries that is presently "neutralised" because of the lack of property rights. The money is potentially there without even relying on foreign capital, but as repeatedly mentioned in this report, the problem of raising this money boils down to the need for broader institutional reforms which go hand in hand with energy market reform. Some of the World Bank's macoeconomic issues related to commercial energy access are set out in the box on page 99.

**2. The Structure of Tariffs, How They Track the Load and Impact Demand**

A common thread in the discussion of energy market reforms is the benefit of competition thanks to a level playing field guaranteed by regulation. One also needs to add the externalities that the market ignores, such as supply security or environmental goals. One might summarise these two concepts as follows:

- Competition is good for the poor as it is for all other consumers because it reveals costs and, in the long run, drives them down thanks to increased efficiency and new technologies. Tariffs should be cost-reflective to best allocate resources and signal the need for investment;
- Externalities such as the social cohesion imperative - "equitable" energy tariffs for the poor - to improve the growth prospects of the country may call for political intervention to correct, not distort, the market if it fails to manage them correctly.

Contrary to a commonly held view, tariffs should not be set to cover the *past* costs because such costs are sunk and can therefore be ignored without economic damage, but to cover *present and future* costs to run a system and develop it. Hence there is the need to look at three different energy costs on the basis of which tariffs are set:

- The fixed payments that cover the costs that tariffs do not pay for, often called "stranded costs", even if this term usually has a more restrictive meaning than that proposed here. The one-time costs of connecting new customers or installing meters are of the same nature;
- The fuel and other variable costs that are needed to run a system. The last plant's variable cost (i.e., that of providing the last kWh or last Btu) is the short-run marginal cost of the system and evidently depends on this last contributor; and,
- The capacity costs that cover the expansion of the system to meet new demand (i.e., the cost of the next set of power plants to cover demand and its load curve or of additional gas production or imports, and the cost of increasing transmission and distribution capacity to deliver the energy services).

No compelling reason exists for charging the first component in the tariff. It has to be identified separately or paid through a separate invoice or by the state budget because, being a sunk cost, it does not impact long-term energy viability. What is important for the sustainability of an energy network - electricity or natural gas – is that the other two energy cost components respectively related to the quantity and capacity be determined accurately and included in the tariff which is charged and paid for the energy service.

To be even more cost-reflective, the two last components may include a spatial (by zone, node or distance) and a time differentiation (by season, week or day):

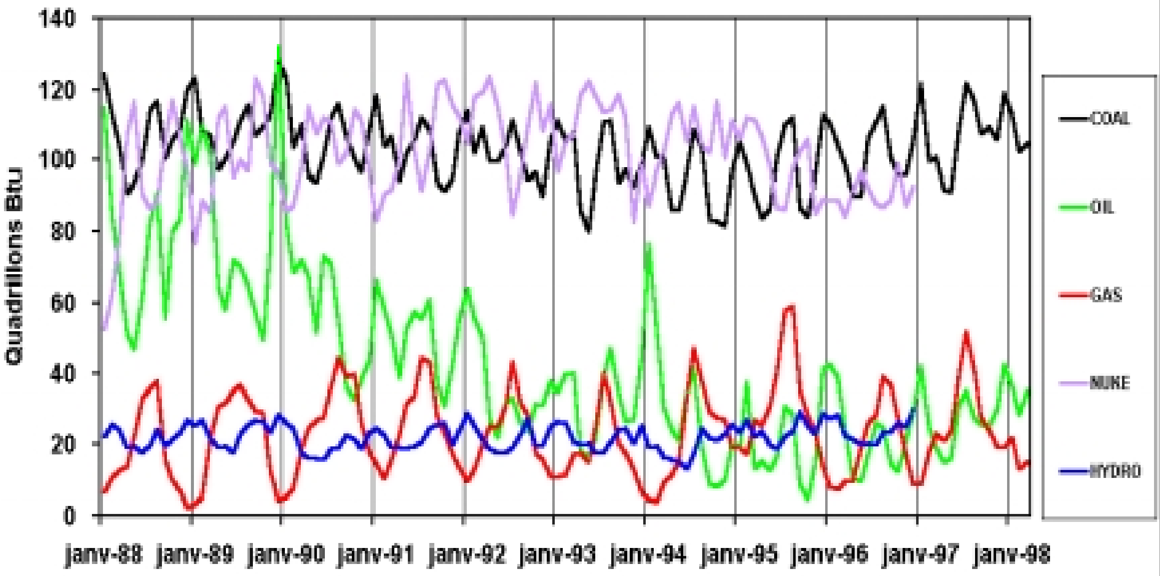
- Spatial pricing is important for natural gas given the long distances involved for its delivery (an order of magnitude of the geographic spread is $1/MBtu for both North America and Europe) but relatively rare for electricity since tariffs are often equalised throughout the national territory in the name of social cohesion and economic development;

- Time pricing is important because consumption of both natural gas and electricity has strong seasonal patterns. It is rarely used for residential/commercial gas customers who have similar load profiles; rather, it is used for the large gas consumers, in particular, the power plants. For electricity, many different formulae exist that reflect a trade-off between the additional cost of smart metering and the benefits that might be expected by the consumer who agrees to level his own load profile.

Because of their specific features, electricity and natural gas tariffs need to be examined separately. In particular, electricity deserves a more detailed review because of the more volatile demand fluctuations. Conversely, natural gas has a buffer storage in the high pressure system (line-pack), thus allowing the market to wipe out most of the small intra-day fluctuations.

*Electricity:* Graph IV-2 shows the seasonal variations of the fuels used for power generation in the northeastern USA. As the electricity demand displays two peaks, one in winter because of the increased use of lighting and heating, and one in summer because of the demand for air-conditioning, the SRMC varies. It is set by coal (nuclear short-term costs are generally lower) during the inter-seasons (spring and autumn), by natural gas in the summer and by petroleum products in the winter.

**IV-2: MIDDLE ATLANTIC & NEW ENGLAND**
**PRIMARY FUELS INPUT FOR POWER GENERATION**




Source: US-DOE-EIA

Reality is somewhat more complex. Weekly (less demand during weekends and bank holidays) and daily demand patterns (strong demand in the evening and depressed demand between 23.00 and 07.00) add to the seasonal variations. Supply also varies because of maintenance (generally during the inter-seasons as shown by the coal and nuclear profiles) and because of breakdowns, irregular hydro and so forth. In some cases, as in Japan, the difference between day and night SRMC is so great (a factor greater than 4) that it justifies the cost of pumped hydro (the excess electricity produced at night being used to pump water up to reservoirs that are emptied during the day to generate power). Such differences create strong incentives to develop distributed energy systems for large commercial and residential buildings, but this will only happen if tariffs are cost-reflective and such developments are allowed by law thanks to energy market reforms[54].

[54] Given that natural gas is the preferred fuel for most distributed energy systems (in such systems, production is geared towards electricity sold back to the network during daytime, and during night time towards either hot water used for heating in winter or cold water for air-conditioning in summer), it is important to reform both electricity and natural gas at the same pace. Should that not be the case, natural gas would be too expensive or electricity could not be sold to the grid.

## Energy and Poverty*

Modern energy remains beyond the reach of many in developing countries. At least 1.6 billion people consume no electricity. In Sub-Saharan Africa, less than 10% of population has access to electricity. Who are the energy poor? The map of the world at night [see page 96] is a now familiar, though still dramatic image. These satellite images of starkly contrasting islands of light and darkness are a forceful reminder of the disparities around the world between those who have access to electricity and those who do not, even for their minimum needs. These disparities are not only between countries but within them. Among the richest fifth of households in Vietnam, 76% have access to electricity; among the poorest fifth, only 27% do. There are also big disparities between urban and rural areas. In Ghana, 62% of the urban population have access to electricity; only 4 % of the rural population do.

What does the lack of modern energy services mean for the poor in their daily lives? It makes their poverty worse. And it makes escaping poverty more difficult. One may stress a number of inter-linkages and synergies.

Energy has direct links with productivity**.** Without adequate energy services, the poor must walk or use animal power rather than travel by motorized transport. They must toil without the benefit of powered machines. And they must forgo more productive activities while they collect the traditional fuels they are forced to rely on for cooking and heating.

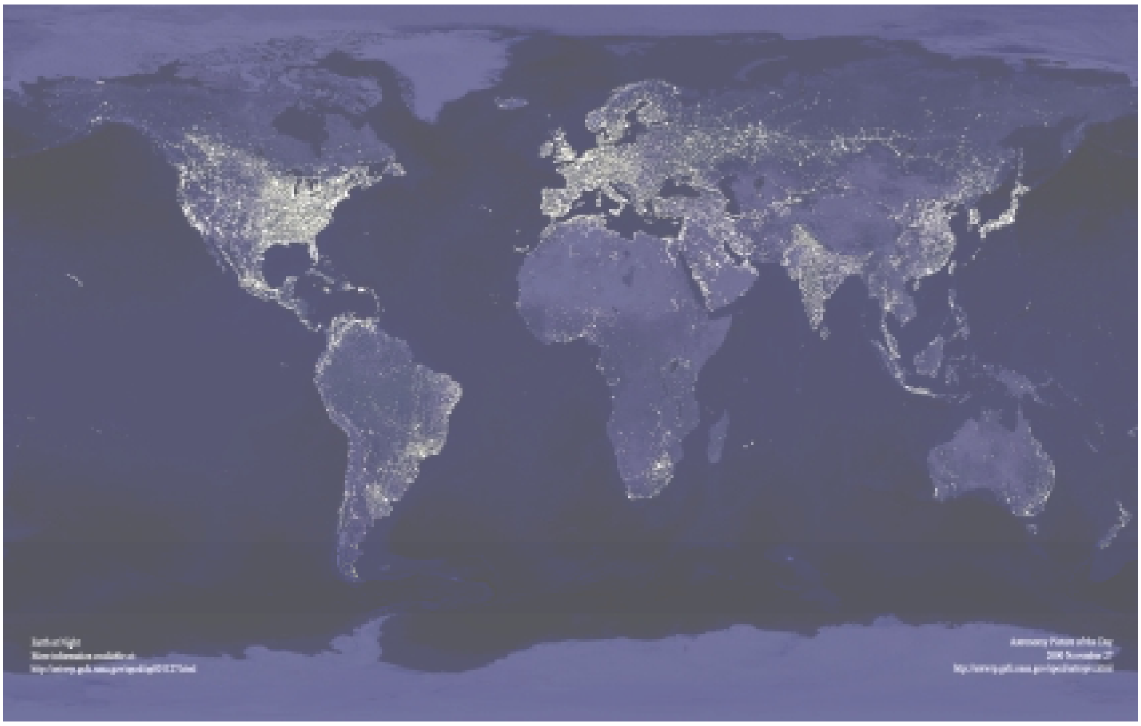
Energy has strong links with national income. Not surprisingly, without energy, most economic activity would be impossible. Large enterprises need a reliable energy supply, and so do the small and medium-size enterprises that provide most new jobs for the poor. The kind of economic growth that creates jobs and raises incomes depends on using more energy and using it more efficiently. So expanding access to modern energy services can directly improve the productivity and well-being of millions of people across developing countries, by providing lighting that extends their workday, by powering machines that increase their output, and by freeing them from the burden of collecting fuel.

Energy has equally strong links with health. About half the world's people still rely on traditional biomass fuels for cooking and heating. And because few have the means to use these fuels safely and efficiently, indoor air pollution is among the leading causes of illness and death in developing countries. Indoor air pollution leads to two million premature deaths a year, more than tuberculosis, AIDS or malaria. In 85% of the developing world's large cities, where the population is growing fastest, air quality is a public health hazard. Airborne pollution from fossil fuels leads to chronic respiratory disease, to premature mortality, to lower IQ in children as a result of lead ingestion, all at enormous cost to families and the economy. A study in Bangladesh found that pollution-related illness forced three-wheeler taxi drivers to miss up to a third of their work time each month, this for people already living on a marginal income. In health clinics, electricity makes it possible to refrigerate vaccines and to operate medical equipment. And in communities, energy makes it possible to provide clean water, by powering pumps and water treatment systems.

Energy has clear links with education too. Lack of electricity in schools prevents access to additional educational materials. So expanding access to modern energy services can directly improve the delivery of social services. In homes, electricity helps to raise children's educational attainment, even where it powers a single light bulb. All these links are reflected in the strong correlation between energy consumption and a composite index of human development. In countries consuming more energy, people have higher income, longer life expectancy and greater educational attainment.

*Extracts from a conference presented by Jamal Saghir, World Bank, Director Energy and Water, at the CERA Week (Houston, 14 February 2002)

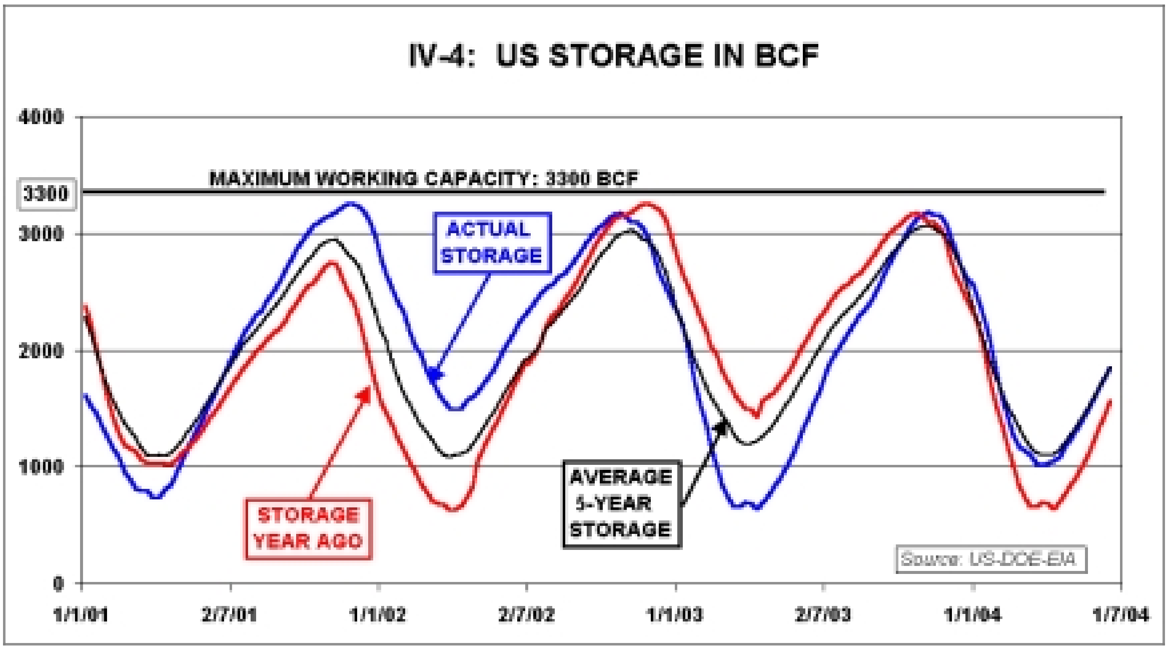
# IV-3: THE WORLD AT NIGHT



Another perspective may be used to understand the importance of capacity costs. Graph IV-2 (on page 98) also shows the importance of base load generation, with nuclear, hydro and coal dominating the capacities, whereas peak or mid load facilities run by hydrocarbons are much smaller. Base load units have high capacity costs versus low energy costs. Mid or peak load hydrocarbon-fired plants also have large capacity costs, in particular because they account for most of the idle capacity margin versus high energy costs when they are run. Thus generation costs are 66% or more capacity-related. With the pure capacity costs of transmission and distribution, electricity tariffs are dominated by capacity costs.

When it comes to electricity tariffs, time-of-use tariffs should reflect the high capacity element, the more so for the residential and commercial sectors, because the additional distribution costs are nearly pure “capacity” costs (the “energy” element is the few percentage points for technical losses). Hence, tariffs should essentially reflect the use of capacities, especially for peak users as households generally are. On the basis of an SRMC approach, consumers should mostly pay for the “energy” component during the low demand periods and pay high tariffs to cover the “capacity” element in addition to the “energy” component in high demand periods. In addition, for given capacity costs, the shorter its time of use, the greater the tariff to recover it. It is a rough rule of thumb that 1,500 hours of peak demand will make the capacity element of the cost six times higher than for a base load profile.

*Natural gas:* As discussed in the introduction of this report, natural gas also displays strong seasonal variations of demand that need to be accommodated in one way or another (seasonal storage, modulation of domestic production, LNG swaps). Everything being equal, the cost of this flexibility should be reflected by the variation of the “energy” component in the tariff between the high and low demand seasons. For the “capacity” element, the rule should be the same as for electricity, that is, that all capacity costs should be paid during the high demand season.




The cost of flexibility varies across the different regions of the world depending on how the seasonal arbitrage is performed:

- By seasonal storage in the USA, where the cost of storing gas from summer to winter, including the financial interests in the value of gas during the time it is kept in storage, is around $0.5/Mbtu;
- By a combination in Europe, with more costly storage and production modulation, costing around $1/MBtu today and potentially doubling soon;[55]
- By LNG swaps increasingly because Europe, to avoid the rising cost of modulating production, will prefer bearing additional costs of terminal/shipping in the order of magnitude of $1/MBtu.

One should assume, for the sake of simplicity, that residential/commercial consumers use gas at full throttle during the six months of peak season and half as much during the other six months. If the average cost is $8/MBtu ($1 for the high pressure grid, $3 for energy and $4 for distribution), the "theoretical optimal" tariffs would be respectively ~$10.5 and ~$2.5/MBtu during the peak and low demand seasons. In fact, the difference will be much lower because such differences lead to flexibility for all of the above-mentioned strategies.

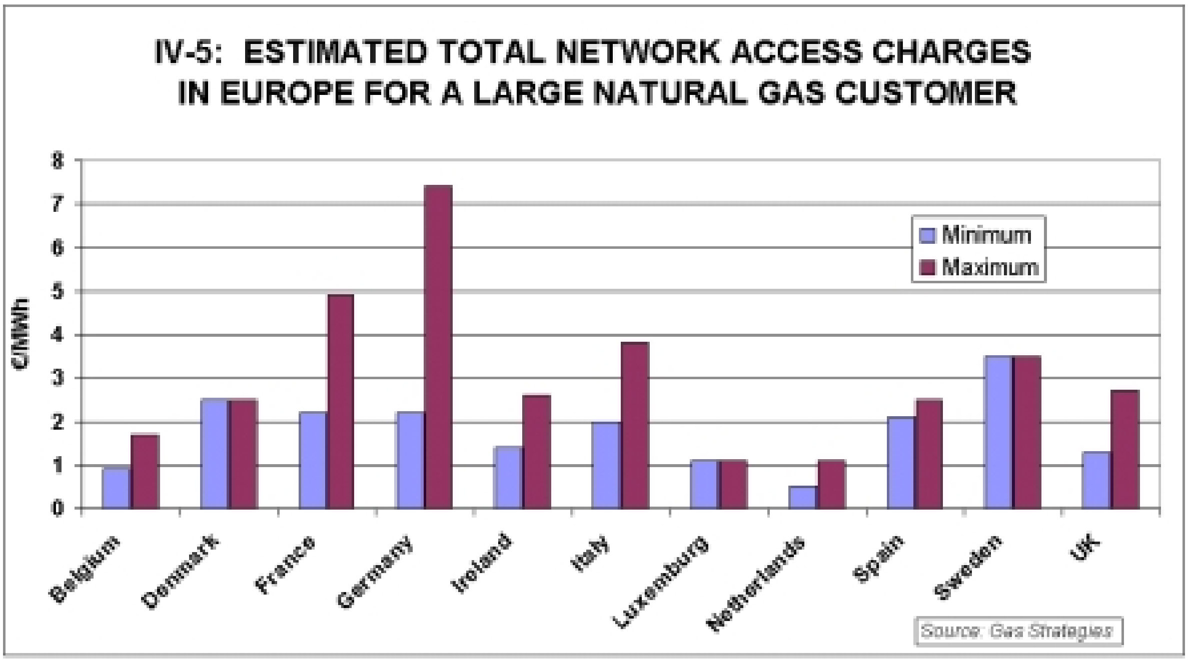
The systematic use of a combination of LRMC (that is, including the capital costs associated with the "capacity" element) and SRMC (for the optimal time-of-use allocation of the costs) lead to time-of-use tariffs exhibiting a much stronger seasonal differentiation than those existing today, with peak season values possibly four times higher than those of the low demand season.

There are two conditions for a cost-reflective time-of-use tariff for natural gas:

- A true spot competition that requires access to the grid on an interruptible basis. This is the case in North America or in Argentina but not yet in Europe, Japan and the few developing countries that use natural gas;

[55] As shown in the introduction, the modulation of production in mature fields is very costly. It is not used any more in Italy and Germany, and the same is soon to happen in the UK and Netherlands. The value of the gas in summer is that of shutting-in production, approximately half the winter value, or about $2/MBtu in the prevailing price environment. LNG arbitrages across the Atlantic Ocean are therefore preferred.

- A strong regulatory framework to avoid the capture of the scarcity rent in capacity or storage by the incumbents. This partly exists in the USA today, thanks to pipeline-to-pipeline and storage-to-storage competition, but not at all in Europe or Japan.




Other regions are still very far from SRMC for natural gas tariffs. For instance, as shown in Graph IV-5, European national access charges are very high, say €2/MWh or \$0.6/MBtu for distances ranging between 100 and 1000 kilometres. In comparison, the average cost to move gas from the south to the northeast of the US over distances of several thousands kilometres is less than \$0.4/MBtu.

***a. How do LRMC/SRMC tariffs lead to adequate investment strategies?***

For LRMC, one should not wrongly conclude that capacity costs only reflect the costs of new capacities in generation, transmission and distribution, whatever the growth rate of the market. In reality, LRMC reflects both the unit costs of new capacities and the amount of annual capacity additions needed to adjust for the expected growth of demand whatever the market structure:

- In a pure spot competitive market, under-capacity episodes will be more frequent and intense if the growth of demand is rapid. The decision process is decentralised and reactive;
- If LDCs remain bundled and must guarantee long-term supply security to their captive customers, they will shop around for the cheapest contracts consistent with their security commitments. In turn, suppliers will offer contracts that pay for both the energy and the expected capacity growth. However, thanks to the competition, too-high expectations of growth will be more costly and sanctioned by the market, thus avoiding the over-investment bias of the former monopolised utilities. The decision process remains decentralised but has become proactive;
- If a “single buyer” system is chosen, it is simpler to develop but relies on a *centralised* decision-making process for the new capacities. The benefit is keeping a central planning function, but the symmetric drawback is a risk of over-investment, as in the former monopolies (an undesirable situation but less worrisome than too little investment leading to under-capacity situations).

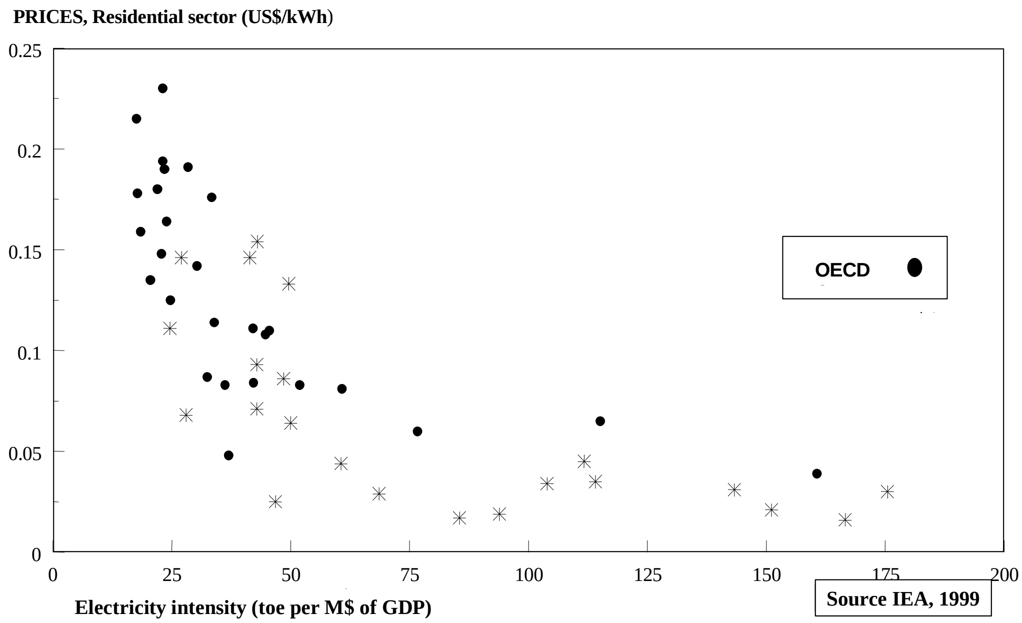
### 3. Subsidies or Cross-Subsidies[56] in the National Interest

Today, real-time demand management is used by large industrial and commercial users, but given recent advances in control, communications, IT and data-management technologies, one may expect demand-side participation of increasingly smaller users. Competition on both the demand and supply sides of the market will then lead to a genuine level playing field, which will enable greater efficiency gains in electricity markets. The extent to which the uptake of these technologies may be accelerated and extended to small consumers depends on the balance between the cost of new equipment and the benefits of levelling the load and avoiding non-technical losses.

Market rules should ease the introduction of demand-side management, and the best way to enhance consumers' welfare is to give them the tools to manage the load and be rewarded accordingly. WEC made this point in ETWAN: "In a well developed, customer-driven energy market, end-user prices are the most important determinant of the level of energy supply and quality of service. Unless such prices reflect LRMC, including, in some cases, the cost of well identified externalities related to energy security or environmental protection, they will distort individual behaviour".

As shown in Graph IV-6, household electricity prices are generally lower in the developing countries than in the industrialised countries because industry often cross-subsidises the household sector. This is done in the name of social policies aimed at improving the access of poor people to energy. While the goal is legitimate, the chosen policies often distort prices, lead to higher consumption than with normal prices, do not address the targeted poor because the benefits are captured by other social groups, and become unsustainable in the long-run (because of the snowballing costs for the State budget in markets with high fertility rates).

**IV-6: ELECTRICITY PRICES IN 1996**
**(27 OECD and 22 non-OECD countries)**




[56] Cross-subsidies mean that some categories of consumers have cheaper than cost-reflective tariffs thanks to other categories which have more expensive than cost-reflective tariffs. Many developed countries have cross-subsidies in favour of industry because industry can "de-locate" whereas small consumers are "captive". It is often the opposite in developing countries to ease the access for the poor. In retail competition, the customers likely to switch will often be cross-subsidised by those likely to remain captive.

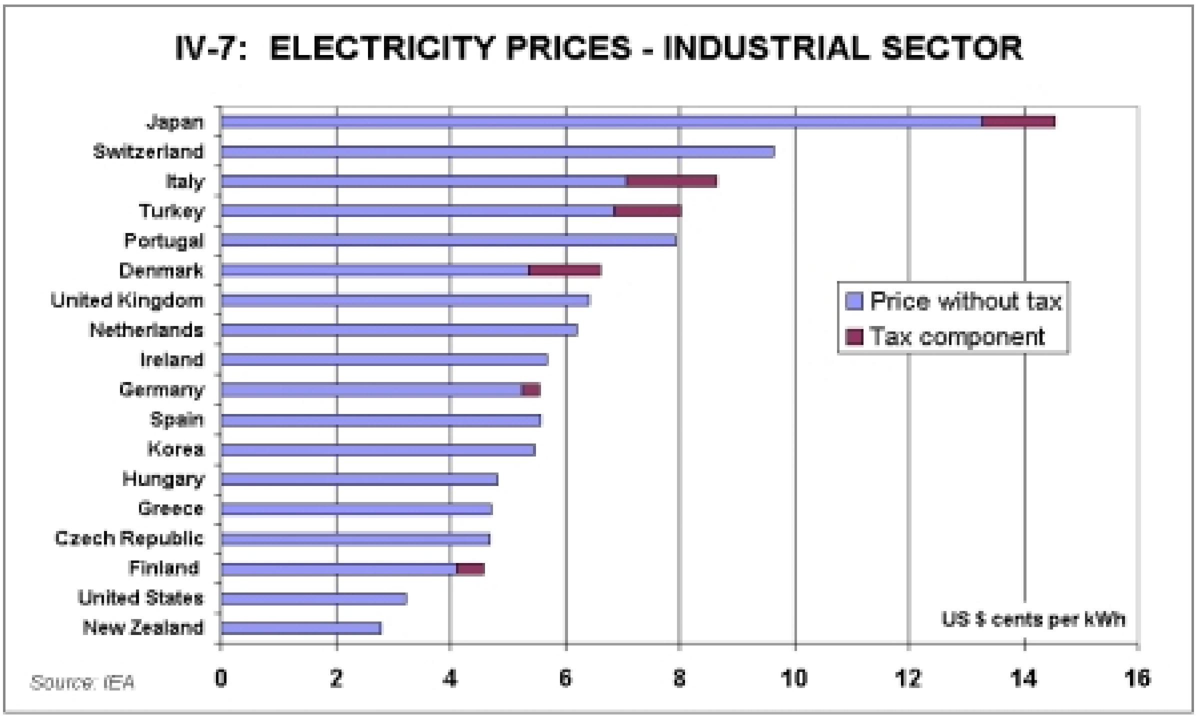
In fact, all countries in the world consider reliable energy an essential service, particularly electricity and, to a lesser extent, natural gas. This explains why governments also tend to intervene in the name of security of supply (short-term reliability and long-term adequacy) even when they have replaced their former state-owned or state-controlled vertically integrated utilities with private-driven competitive markets. For households, social policies are usually tackled in one of three ways:

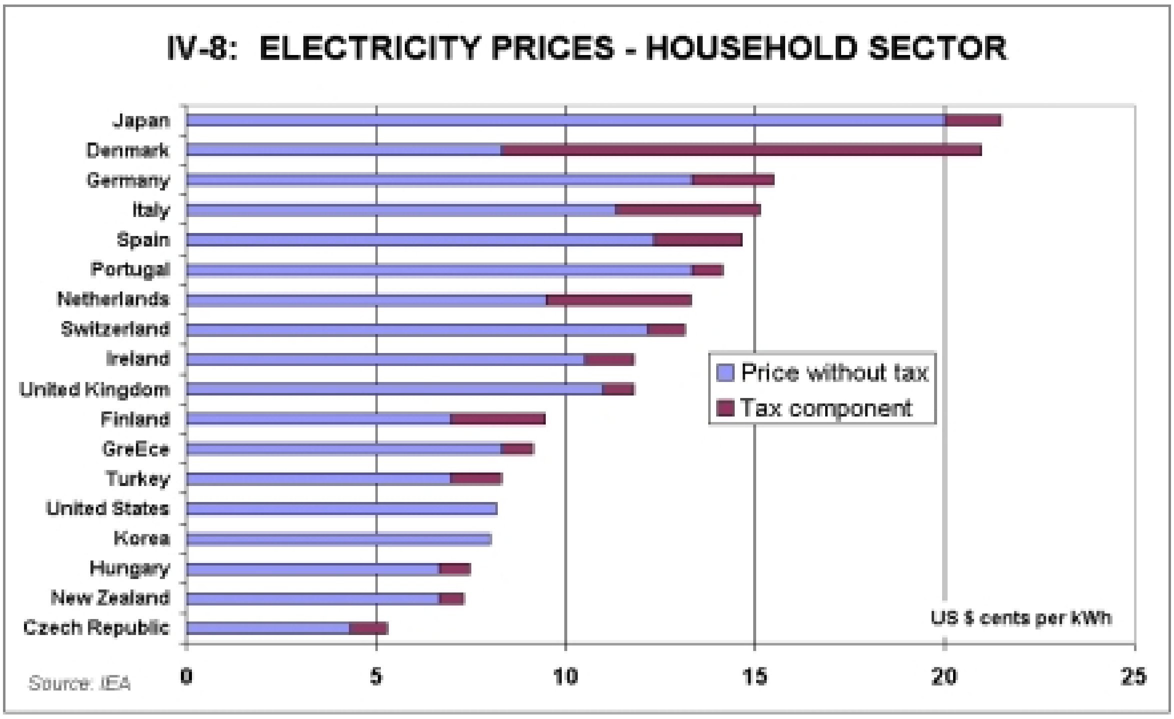
- The recognition that the cost of the energy bill, expressed as a share of personal disposable income, is much greater for the poor, thus creating the need for appropriate lifeline policies;
- The territorial equality of costs, in particular, for basic essential services such as electricity. This is, for example, the case in France with identical tariffs in metropolitan France and the remote islands under its jurisdiction;
- The levelling of access charges whatever the distance from the main grid, especially for electricity. Milder forms of such policies exist with only part of the costs being subsidised.

Such policies call for a good balance between the governments' goals and the means to achieve them. Generous subsidies too often create unsustainable deficits that end up working against those who were supposed to be protected. As discussed later in this report, it is important that policies in favour of the poor should be well targeted and sustainable by avoiding "subsidy capture" or distortions that snowball into the bankruptcy of the incumbent utilities. Direct transparent subsidies to the "right" consumers with sunset clauses or re-distribution policies through lower and possibly negative income taxes supporting the "right" parts of the population should be preferred.

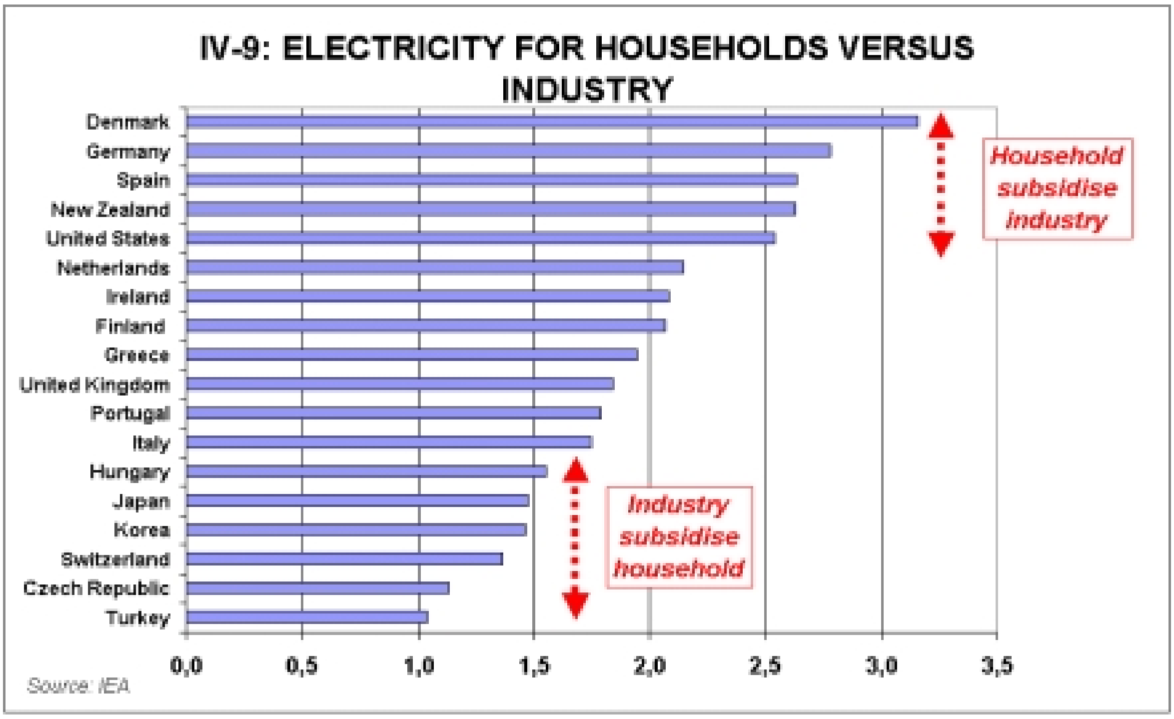
Sustainable energy of any sort is not a free public good. Energy market reforms are a powerful driver for LRMC-reflective pricing that ensures reliable energy provision if consumption is metered, billed and paid. Reforms also create a transparent, competitive level playing field, generally wiping out subsidies and cross-subsidies, at least to the extent that such reforms address cost-reflective pricing as a priority.

Many developed countries do the opposite of developing countries in terms of cross-subsidies in the electricity sector, although there are important exceptions. They lower industrial energy prices at the expense of the captive users via lower tariffs (e.g., pricing gas as if the customer was interruptible) or taxes to enhance their international competitiveness. Graph IV-7 shows electricity prices for industry in a number of selected countries and needs to be compared to the prices for the household sector in the same countries which are shown in Graph IV-8.






Graph IV-9 shows that on average, the price for households is twice that for industry in OECD countries. As distribution costs for households explain two-thirds of the difference, the last third reflects the average cross-subsidy in favour of industry, half through wholesale tariffs and half through taxes (20% for the residential sector and 5% for the industry sector).

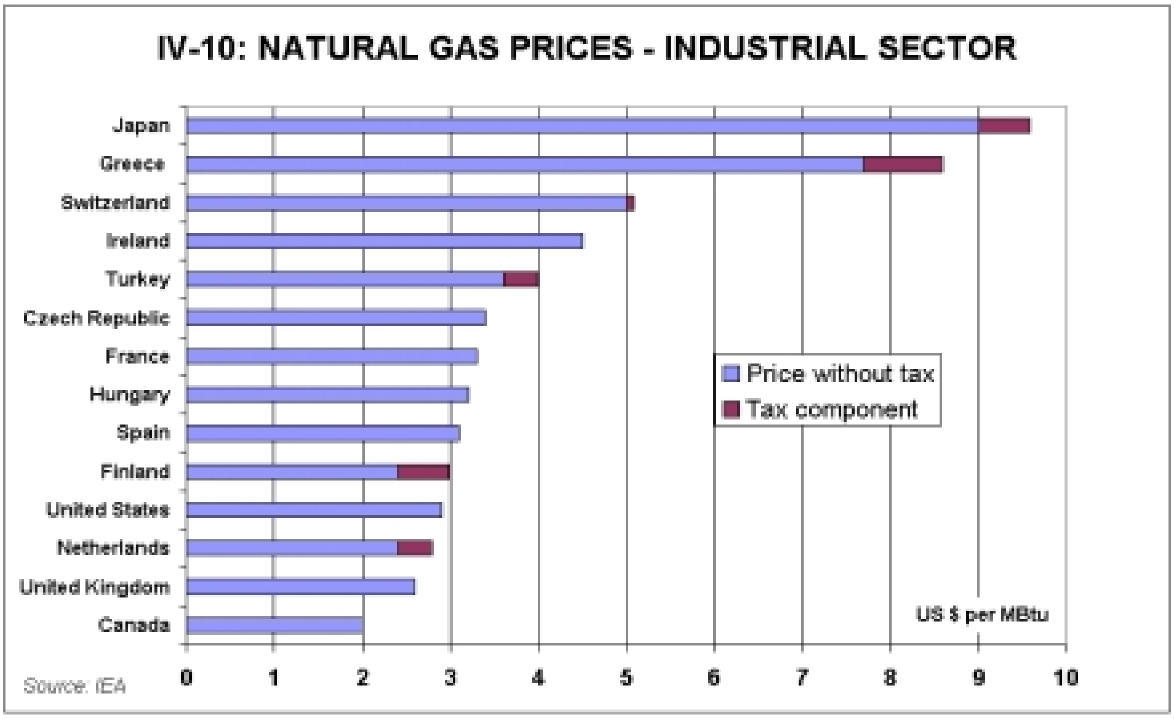



Natural gas exhibits the same kind of cross-subsidies as electricity. A specific example is set out in the table on the following page for Spain, where taxes (about $1.5/MBtu on light fuel oil used by households versus $0.25/Mbtu on heavy fuel oil used by industry) provide a differential rent to the natural gas used by industry.

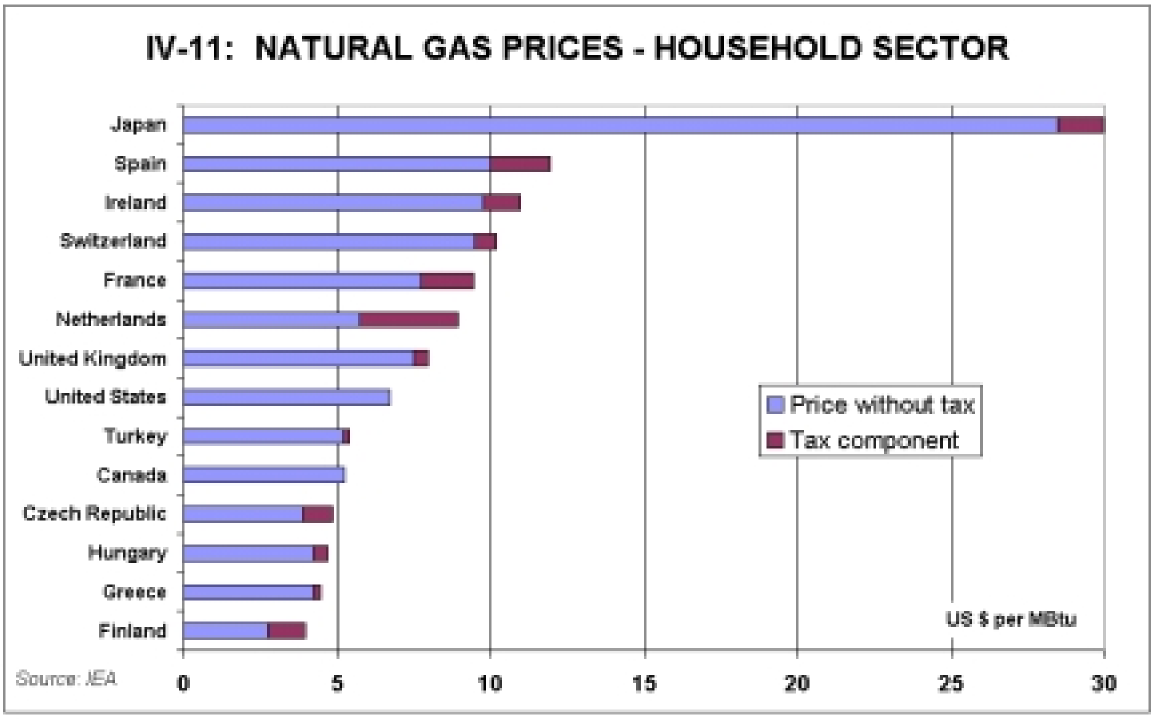
**Energy Taxes in Spain in 1999**

| Sector/Fuel | Excise tax (Pesetas per unit) | VAT (%) |
|---|---|---|
| Households/electricity | 0.94/kWh | 16 |
| Households/natural gas | 0 | 16 |
| Households/light fuel oil | 13,097/1000 litres | 16 |
| Households/coal | N.A. | 16 |
| Households/gasoline, leaded | 67.35/litre | 16 |
| Households/gasoline, unleaded | 61.84/litre | 16 |
| Households/diesel | 44.90/litre | 16 |
| Liquefied petroleum gas in a 12.5 kg cylinder | 1,227/kg | 7 |
| Industry/electricity | 0.42/kWh | 0 |
| Industry/natural gas | 0 | 0 |
| Industry/light fuel oil | 13,097/1000 litres | 0 |
| Industry/heavy fuel oil (whatever sulphur content) | 2,235/tonne | 0 |
| Industry/coal | N.A. | 0 |
| Industry and commercial/diesel | 44.9/litre | 0 |

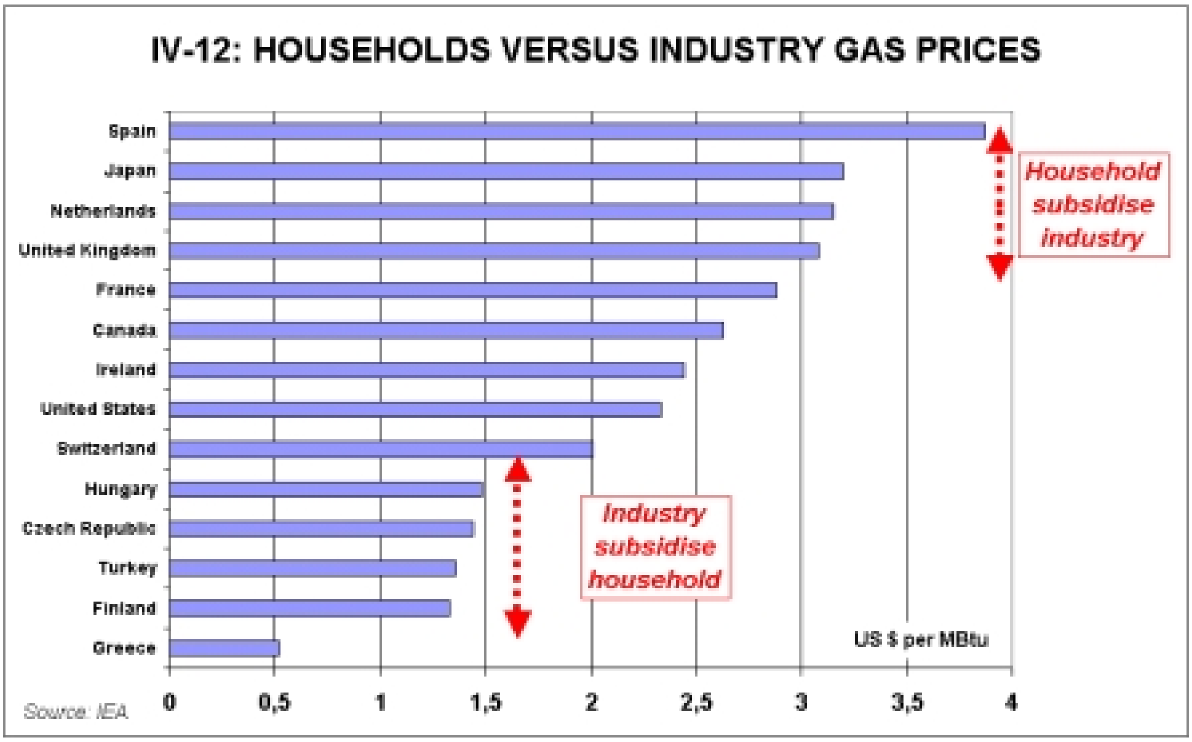
Sources: Energy *Prices and Taxes,* IEA/OECD Paris, 2001, and Energy Administration/Ministry of Economy.
Note: A peseta was worth 0.4 cents of Euro or US Dollar in 1999




With the exception of Canada, the Netherlands and the United Kingdom, which are net exporters of natural gas (although the UK will soon become a net importer), Graph IV-10 shows that 2002 prices in the industrial sector were at a similar level of $3-4/MBtu in most big consuming countries. Higher prices exist in Turkey and Greece (which are nascent markets), Ireland (which depends at the margin on imports from the UK), Switzerland (which is land-locked) and Japan (which is totally dependent on high-priced LNG imports, costly domestic anti-seismic infrastructures and lack of competition). Graph IV-11 shows the data for households.




Graph IV-12 provides a comparison of the two sets of after-tax prices. On average, the ratio is 2.3, with distribution costs – higher for natural gas than for electricity - representing up to 77% with the remainder being an average cross-subsidy in favour of industry. About half of this subsidy comes through wholesale tariffs and half through taxes which, on average are 12% for the residential sector and 5% for the industrial sector.



## 4. Ensuring Affordable and Sustainable Energy Access to the Poor

The analysis thus far and, more specifically, that dedicated to the structure of tariffs which track the load, confirms the viewpoint of ETWAN, published in 2000:

- The difference between sunk costs (stranded costs or one-time costs) and LRMC does not affect long-term energy sustainability and may therefore be subsidised by the state without undue distortions;
- Load-tracking costs (similar to SRMC but with the long-term capacity element) are mostly made of capacity costs and are therefore smaller for base load users; and
- Metering should work hand in hand with time-of-use tariffs to allow end-users, in particular the poor, to adapt their consumption cheaply and efficiently.

### *a. How to treat the sunk costs?*

Such costs exist when initial unit capital costs are greater than the unit costs of expansion. It happens each time economies of scale are captured as the system grows. This also happens for siting costs because the first unit of a greenfield project will have to bear costs that the following units will not; similarly, for transmission, transportation and distribution it is less expensive to upgrade or expand an existing network. In all these cases, long-term marginal costs (LRMC) will be lower than historical costs. A last case of sunk cost is that of the installation and instalment of the meter, which, once in place, only needs maintenance.[57]

What do theory and common sense tell us about sunk costs? At the time of the monopolies, all costs, including non-recurring up-front costs, were recovered by "ad hoc" tariffs. Market reforms oblige governments and regulators to find new explicit solutions, as simple and unbiased as possible, to make certain that competition and the market will operate properly and that costs will be paid, one way or another. A justifiable solution is to cover that proportion of capital cost in excess of the LRMC with an explicit, transparent subsidy.

This solution makes sense not only for greenfield projects but also for the stranded costs[58] incurred by incumbent utilities when market reforms are introduced. They should be "subsidised" in one of several ways: by a levy on the price of electricity consumption (the classical solution); by a "gift" from the state to the investor of similar value, e.g., a 30-year franchise for a new hydro dam project; or, ideally, by the general state budget in the form of a direct subsidy paid to the investor/owner from the public purse[59] (a solution that would allow the market to rely on long-run marginal costs to set prices). In the latter two cases, a tendering process might be useful to determine how low the gift or direct subsidy could be kept to support a successful bid.

Conversely, it would be an error to consider that the supply of a fully amortised plant, in particular, a facility with a very long lifetime, such as a hydro facility (that may extend over a century) or a nuclear plant (that will, in current experience, extend well over 40 years), should be provided on the basis of its SRMC because the capital cost of the plant has been "written off". Marginal cost pricing theory delivers a different message, namely, that the rent should go to the state, not to the users,

[57] The Argentinean experience is interesting. They subsidise the poor for the installation costs (meter and wiring) because it was noted that this cost is the main obstacle to regularise the illegal connections; the consumed energy is not subsidised.
[58] In the USA, after the collapse of gas prices in 1986, the process of getting rid of the long-term high-priced natural gas contracts signed in the early 1980s was long and painful. For electricity, the experience of the FERC is that stranded costs are generally lower than they were expected to be. More generally, stranded costs might be low when tariffs before deregulation were cost-reflective and initial siting costs were not too expensive, but high in the opposite case (such as Japan).
[59] This is what was done by the Singapore Authorities for the new metro. The initial investment cost was paid by the general government budget and the tariffs were set to reflect the long-term marginal cost, which is a combination of variable costs, full operating costs and the costs of expansion of the system.

with the power supplied by these plants paid at the current LRMC [60], a price possibly higher than what it was when the plant was built!

***b. Load-tracking costs***

Pure energy costs (i.e., the costs of fossil fuels burnt in the power plants, the costs of losses on the wires, the auto-consumption in the gas pipes) are variable but are only a small part of total costs (indeed, they are very small for countries relying mostly on hydro and/or nuclear). All other costs to run the system, such as maintenance or manpower, are fixed costs, because it is difficult and costly to delay maintenance and nearly impossible in practice to lay off personnel. Variable costs should, therefore, be viewed as a part of the much larger capacity element, which should be charged to customers on the basis of their load profile. Base load users should only pay for the units that are run for base load, and the consumers with load swings should be charged the corresponding costs during their peak demand. In practise, one can establish a standard load profile for each residential or commercial category, even to the point of distinguishing the different types of commercial/services users and, within the residential sector, the different classes of customers with different peak versus annual demands.

As shown earlier in this report, one has to clearly distinguish between supply and distribution tariffs because the former are related to a regulated activity, whereas the latter are related to a competitive (if retail competition is implemented) or potentially competitive (for the categories of customers who still have a bundled service) activity. In addition, distribution and supply load profiles may be different (when the peaking of demand of a given customer does not coincide with the average peaking of the system) and also calls for such a distinction.

Combining the two services into a unique tariff brings the risk of cross-subsidies with other categories of customers. Hence a bill in which the two services are identified and priced separately is a minimum requirement for customers who cannot get their supply competitively, in particular, the largest of them (small industries and large commercial customers who generally have distinct load patterns, especially when they can modulate their demand profile as a function of the tariffs).

For large commercial/services users, smart meters may be proposed, with more or less sophisticated time-of-use pricing features, from the dual-tariff system (day versus night and weekdays versus weekends and bank holidays) to a system with automatic remote load-shedding. For the residential sector, in particular, in developing countries, a simple cost-benefit analysis will help identify the classes of households for which sophisticated metering makes sense versus those recently or about to be connected who need a minimum amount of electricity service, in particular the poor, for whom a simple, straightforward system is key. What is important in all cases is that all households be metered in some way, the energy service consumption billed accurately and the payments collected systematically.

***c. Tariff-setting, the case of the poor***

For all users, including small captive households, tariffs need to combine a fixed and a proportional element. One-time lump payments may seem attractive when fixed costs are dominant, but since they are not related to actual consumption, they would eventually create distortions by favouring higher consumption than would otherwise be the case.

[60] This kind of situation creates a rent that should not be incorporated in the electricity price but be given back, either to the state for hydro (the natural resource rent that can be captured by re-auctioning the dam every 20-30 years) or to the owner for nuclear.

Hence, a proportional element in the tariff is indispensable, the more so if it reflects the shape of the load [61], that is, the proportional element is higher for categories having the lowest annual utilisation rates.

At this stage, it should be recalled that the analysis developed for the captive sector assumes that retail supply and distribution remain bundled unless the user agrees to pay a severance cost. Even in the case of full retail competition, one would expect the poor to be a special category under the responsibility of a last resort supplier with a lifeline, but temporary subsidies for the fixed element in the tariff. If this were the case, the basic rules of tariff-setting applying to all market situations could be summarised as follows:

- High utilisation rate users (the case of industry and, as discussed below, a potential way to address the poor) should pay low proportional tariffs reflecting the full cost of base load supply;
- Users calling for energy during the troughs of demand should pay only the corresponding variable costs (low or even negative, as in Norway during summer because of the need to consume the available hydro electricity) without capacity costs;
- Low utilisation rates user (i.e., the mid or peak load customers) should bear tariffs reflecting the capacity costs of the whole system. Time-of-use prices should signal the situation and help them to change their load profile either directly or through investments in distributed generation systems.

As this report deals with energy networks, access is mostly discussed in terms of urban or peri-urban poor. WEC has undertaken a special study of urban energy poverty in Latin America with three cases, Buenos Aires (completed), Rio de Janeiro (soon to be completed) and Caracas (just launched).

The case of rural or off-grid energy customers has been addressed in several WEC studies, and in current ongoing work in Africa, where the challenge of energy accessibility is particularly acute. Regions where no network exists because of a scattered population raise specific issues that have also been extensively studied by the World Bank. There are several approaches to rural energy poverty:

- The "dealer model", which builds on existing retailer networks that service rural areas;
- The "concession model", with private franchises awarded to firms requiring the smallest subsidy;
- The "retailer model", based on a local business developing a plan to provide local service.

Off-grid customers also create specific challenges in terms of subsidies that should encourage service provision and not only the purchase of equipment.

The urban poor in or near grid-based systems can get lower tariffs if they use low capacity meters that prevent peak demand and level the load at an average higher utilisation rate. This is an easy means to provide a cheap basic supply of electricity at an affordable price.[62] In addition, the funding of the sunk costs by the general budget would allow lower tariffs without distorting them.

[61] As already mentioned, load profiling is important because the consumers who contribute to the peak should pay according to the LRMC/SRMC rules. It may happen that the use of local wires or pipes is different from that of the wholesale market and that two separate load profiles need to be taken into account, one for the supply and one for the distribution. Conversely, when the two load profiles are similar, it may be less costly to have a unique tariff for the energy and the infrastructure.

[62] This is probably the reason why, in Spain, there are very low-capacity meters of 0.7 kW for the poor as compared to the more standard 3 to 9 kW that are normally available for the residential sector.

ETWAN addressed the question of sunk costs and proposed their payment by the state budgets. It also addressed the question of cost-reflective, load-tracking pricing and how it might be used to propose lower tariffs for the poor. Four years later, WEC reconfirms the viewpoint presented in ETWAN on this important topic:

> "*It is a well-established policy to adopt a tariff which will offer a very low price to the poor, defined as those requiring less than a certain threshold capacity or consuming less than a certain quantity of electricity. While economic theory suggests that prices should reflect the long-term marginal cost of energy, i.e., the variable and other costs, such as maintenance and expansion of the system (generation, transmission and distribution capacities), it also says that such prices may not cover the initial investment when economies of scale and learning curves exist. This is generally the case for the provision of energy, and this should certainly apply to the poor from whom initial sunk costs should not be recovered in energy tariffs but rather, through the general budget of the country.*
>
> *One way in which this policy can be pursued is through the limitation of accessible power (e.g., to a few hundred watts) which will allow a more or less base load consumption. Thus most of the initial sunk cost for the creation of the infrastructure and installation of the meters will be subsidised in order to leave, for this category of customers, a low and rather symbolic monthly fixed charge. In addition, because of the base load pattern of consumption, the commodity cost will only reflect the costs of the base load power plants, which may be as low as a few cents per kWh, as well as the costs of maintenance of the system (power plants, transmission lines and distribution grid).*"

***d. Energy subsidies***

Energy subsidies are frequent, and subsidies for remote rural populations and the poor exist in both developed and developing countries. In addition, as shown earlier in this report, there are often cross-subsidies that favour either the industry or the residential sector. Economists would ideally prefer the removal of such subsidies, but in the real world, one needs to identify where they are and the way they work to ensure that they do indeed help the poor and can be designed to be economically sustainable in the long run.

An example for the industrialised countries is that of New Jersey (USA), reported in the *Philadelphia Inquirer* (22 March, 2003). Low-income New Jersey residents get help paying natural gas and electric bills under a program approved by the State Board of Public Utilities. The Universal Service Fund will pay as much as $1,800 annually per household. "One of the Board's primary responsibilities is to protect ratepayers and to ensure there are programs and services that assist our most vulnerable citizens," the Board's president, Jeanne M. Fox, said in a statement that announced the plan. Those qualifying must have income no greater than 175% of the federal poverty guidelines. Participants in the Universal Service Fund pay no more than 3% of their income for electricity and 3% for gas, or 6% for those with only electric service. The fund is mandated under the Electric Discount and Energy Competition Act of 1999, which establishes assistance programs for low income residents.

An example for the developing countries is that of the Kyrgyz Republic, analysed by the World Bank. On average in 2001, household energy expenditures were nearly twice as expensive in relative terms for the poorest quintile as for the richest quintile in that economy. A further problem was that households often did not trust the billing system and did not know what to do if they have been wrongly billed. Adding to that, subsidies had been cut by the government, which improved the state budget but forced energy users to reduce their consumption and switch to dirtier fuels (such as coal, fuel wood and even dung and peat) associated with indoor and urban air pollution. The government's new strategy is to compensate the poor households for the higher cost of the unsubsidised electricity with a cash transfer using the existing social protection system. Unfortunately, this is a very inefficient approach. Not only are the costs to administer the system high, but fresh government analysis indicates that only 13% of extremely poor households receive social assistance at present, and 73% of the recipients are better off than the extremely poor. Non-technical losses in the Kyrgyz Republic (related to theft of electricity or unpaid bills) remain high.

This example has a universal bearing. In WEC's 2001 publication, *Pricing Energy in Developing Countries,* case studies of nine countries were carried out. It is extremely difficult to design a consumer subsidy programme which is well targeted, transparent and temporary, but if government programmes to assist the truly poor do not work, the non-technical losses remain high and economic progress is thwarted. While the ideal solution, when assistance to the poor for access to a minimum amount of commercial energy services is justified, is to keep energy tariffs on a purely economic footing (that is, cost-reflective) while using re-distributive income tax policies to cover direct transfers of assistance to the poor, experience shows how hard this is to achieve in developing countries where institutions are often too weak to support such a theoretical approach. Such taxes are difficult to implement because the declared income of poor people often does not reflect their actual income and because part of the income of the most wealthy citizens escapes taxation. The World Bank has suggested the use of vouchers for the poor to acquire a minimum amount of commercial energy service, but again, the Kyrgyz Republic experience shows that it is difficult to identify those who really need them and avoid vouchers falling into the hands of those who do not.

This is the reason why countries often rely on subsidised tariffs to help the poor. Surprisingly, direct energy subsidies can be targeted to the poor more easily than income support because there is an objective criterion that can then be used, that of the actual consumption of energy [63]. Subsidised tariffs can be offered to those who consume less than a given threshold of electricity. This requires the retail supply be tightly controlled through the metering of actual consumption and the elimination of non-technical losses. Poor consumers will then benefit from lower fixed costs and/or lower prices per kWh.

In short, while it is essential to have cost-reflective energy tariffs and for these tariffs to be actually paid by the users of the energy services, appropriate low-capacity meters for the poor can be linked to low costs and prices. If lifeline subsidies are also required in a particular situation or market, it is possible to design lower, temporary, transparent tariffs targeted to those whose electricity consumption is below a certain threshold.

### *e. Public service*

The concept of public service is ambiguous because it covers and often confuses three different issues:

- The problem of ownership (public or private) of the energy companies;
- The political and social goal of providing universal electricity service; and
- The need for affordable tariffs for the poor.

These issues are important but should not obscure the word "service" or the need for energy to be truly provided as a "service". All energy "users" (the term used to describe individual clients by the monopolies of yesteryear) and even more, the poorest, should be treated like "customers" with a respectful and transparent interface. That means that customers, including the poorest ones, should have "rights", know these "rights", and be sure that these "rights" are respected. The notion of service, therefore, goes even further in the sense that customers' questions have to be heard and addressed, their bills have to be explained and, when wrong billing or a service failure occurs, the situation must be duly and rapidly corrected.

[63] On 8 April, 2004, J.P. Raffarin, Prime Minister of France announced the creation of a social electricity tariff for households with less than € 5,520 per year total income. This will apply on the first 100 kWh monthly of consumption and on the subscription cost. 1.6 million families are expected to benefit, at a total annual cost of €100 M.

In this context, regarding ownership, it is at best uncertain that state ownership provides a better "service" than privately-owned competitive systems. As Jenny Kirkpatrick, CEO of the UK Electricity Association, said when she was asked whether public service and competitive liberalised markets were mutually contradictory, "Public service is not lost in a liberalised market, it comes to the fore and, in fact, UK customers show the highest rate of satisfaction among EU citizens. The thirteen years of open market in the UK have clearly shown that excellence in customer service quality is compatible with competition. The customer has the right to expect minimum standards and to complain and receive compensation if these are not met". It is worth noting, with respect to the UK energy market, that compensation payments have declined from 13,000 cases in 1991 to 3,000 in 2001.

Regarding accessibility and affordability, all countries have special programmes to help the poor. As Jenny Kirkpatrick has said, "UK suppliers also have special approaches to serving vulnerable customers and those deemed to fall within the fuel poverty category (where over 10% of disposable income is spent on heating and lighting homes." However, while the rich countries can afford the cost of such social policies without compromising the sustainability of their electricity system, the poor countries are faced with attracting the necessary domestic and foreign money to build and extend capacity; they have to be extremely careful and design their policies in a way that does not threaten the long term sustainability of their energy systems.

Electricity companies cannot survive if subsidies via the tariff become a more or less permanent feature of the system or snowball to uses and categories of population that do not really need them, or if electricity demand is artificially increased because of such programmes. And it is not just the electricity company or system which can be affected. Where a natural gas market also exists, each time electricity is used instead of gas, two or three times more primary energy is used than would be the case without distortions.

It is clear that "public service" is of fundamental importance. Its primary significance is in terms of "service to the public" and not as a reason to maintain publicly-owned monopolies. The stakes are considerable in terms of social balance and economic development. A sustainable and affordable level of quality energy services is vital for everyone, especially the poor, and is an imperative that calls for carefully designed reforms aimed at ensuring the long term efficiency of energy companies, the training and motivation of their employees and the education and awareness of customers about the trade-offs which energy market reforms require.

**5. Summary of Part IV: Tariff-Setting and Energy Poverty**

Consumers are the "alpha and omega" of energy market reforms, either directly in developed countries or indirectly in developing countries that seek capital to fulfil their growing energy needs. In this respect, tariffs should reflect the workings of the electricity or natural gas systems in order to make relevant decisions and become the drivers of development, social cohesion and economic growth.

When it comes to tariff-setting in the context of energy market reform, four issues have been discussed:

- The significance of sustainable energy access in terms of national development;
- The structure of tariffs based on the load patterns of consumers;
- The parameters of subsidies in the national interest; and
- The provision of affordable and sustainable energy for the poor.

*The significance of sustainable energy access* is enormous. Even though energy is not the only basic service, it is the most important, because without energy, there is no clean water at the tap, no health care, no education and information and no way for a country and its people to get on the development path. Sustainable access to energy needs to be a national undertaking for the sake of the country, its people and greater world harmony.

*The structure of tariffs* is key to send the appropriate signals to consumers about the choices they make. In this domain, very simple approaches based on the maximum required capacity and average energy consumption allow one to track the load fairly well for broad categories of customers without relying on smart time-of-use meters that may still be too expensive in some markets.

*Subsidies and cross-subsidies* are not the best theoretical approach but exist in all countries to a greater or lesser extent. WEC has often made its position clear on subsidies: producer or cross-subsidies in the energy sector should be avoided, but consumer lifeline subsidies may be needed to address the energy access needs of the poor; if so, such subsidies should be targeted, transparent and temporary. While direct consumer subsidies from the public purse are theoretically better than tampering with the electricity tariff, there are ways in which the lifeline can be built into it.

*Supporting the poor* involves programmes which combine the most relevant tariff approaches, the elimination of the "stranded" costs in excess of the LRMC, the use of low-capacity meters to level the consumption load and the possible reliance on a direct tariff-based subsidy applying only to consumption below a certain threshold by a specified category of customer.

**ANNEX A**

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**ANNEX B**

## STUDY GROUP MEMBERS AND INVITED EXPERTS

### Study Group Members

| | |
|---|---|
| Dr Pablo Mulás del Pozo | Chairman Study on EMR<br>President's Office Universidad Autónoma Metropolitana, MEXICO |
| Mr Jean-Marie Bourdaire | Project leader, WEC Director of Studies, UK |
| Mrs Fawzia Abou-Neima | Ministry of Electricity and Energy, EGYPT (Arab Rep.) |
| Mr Mohsen Bakhtiar | Ministry of Energy, IRAN (Islamic Rep.) |
| Dott Massimo Beccarello | Direttore per le Public Utilities e la Concorrenza Confindustria, ITALY |
| Mr Nourredine Boutarfa | SONELGAZ, ALGERIA |
| Dr Alessandro Clerici | ABB, ITALY |
| Dr Chris Cooper | South African Energy Association, SOUTH AFRICA |
| Prof Adilson de Oliveira | Instituto de Economia Universidade Federal do Rio de Janeiro, BRAZIL |
| Mr Daniel Dumas | SNC-Lavalin, CANADA |
| Mr Arne Faaborg Povlsen | ELSAM A/S, DENMARK |
| Dr Alioune Fall | Power Sector Regulatory Commission, SENEGAL |
| Shri Sajal Ghosh | Confederation of Indian Industry, INDIA |
| Mr Ahmed Hafsi | Utility Company in charge of Petroleum Products Facilities, TUNISIA |
| Ms Sheila Slocum Hollis | Partner Duane Morris LLP, USA |
| Mr Peter Høstgaard-Jensen | ELSAM A/S, DENMARK |
| Mrs Sevinç Kiciman | WEC Nation Committee, TURKEY |
| Dr Bo-Young Kim | Korea Gas Corporation (KOGAS), KOREA (Rep.) |
| Dr ir Kees-Jan Kuijlaars | Office for Energy Regulation, NETHERLANDS |
| Dr Willa Le Roux | Marketplace Company South Africa (Pty) Ltd, SOUTH AFRICA |
| Mr José Sierra López | Comisión Nacional de la Energía, SPAIN |
| Mr Ichiro Maeda | Tokyo Electric Power Company, JAPAN |
| Mr Jyoti Mehta | WEC Member Committee, INDIA |
| Mr José Luis Montes | UNION FENOSA (Utility), SPAIN |
| Dr Rolando Nieva Gomez | Instituto de Investigaciones Electricas, MEXICO |
| Mr Kieran O'Brien | EIRGRID, IRELAND |
| Mr Nadjib Otmane | SONELGAZ, ALGERIA |

| | |
|---|---|
| Dr Jens Perner | RWE AG, GERMANY |
| Dr Eng Vasile Rugina | ICEMENERG SA, ROMANIA |
| Mr Bob Pritchard | Resources Law, AUSTRALIA |
| Mr Fieke Rijkers | Energy Research Center, NETHERLANDS |
| Dr Hardiv Situmeang | PT PLN (PERSERO), INDONESIA |
| Dr Jan Sundell | VATTENFALL, SWEDEN |
| Shri Tantra Narayana Thakur | Power Trading Corporation of India Ltd, INDIA |
| Mr Kartal Usluel | USLUEL Energy Inc, TURKEY |
| Mr Graham Ward | PricewaterhouseCoopers plc, UNITED KINGDOM |
| Mr Mario Wiegers | EDESA Ingenieros Consultores, ARGENTINA |
| Mr D. Wijeratna | Ceylon Electricity Board, SRI LANKA |
| Mr Hussnain Zaigham | National Electric Power Regulatory Authority, PAKISTAN |

**Invited Experts**

| | |
|---|---|
| Mr Jorge de Vasconcelos | Entidade Reguladora dos Serviços Energéticos (ERSE), PORTUGAL |
| Dr Nils Flataboe | SINTEF Energy Research, NORWAY |
| Dr Graham Thomas | GT Power Consultants Ltd, UNITED KINGDOM |
| Prof Raymond Leban | Conservatoire National des Arts et Metiers (CNAM University), FRANCE |
| Mr William Webster | European Commission, BELGIUM |

**ANNEX C**

## DEFINITIONS AND CONVENTIONS

### 1. "Market"

The title of the study is *Energy Market Reforms*, and the use of the word "market" and the combination, "market reforms", will have different interpretations for different readers. For example, "industry reform", "tariff reform", "regulatory reform", "increased access" and "liberalisation" are all considered as "market" reforms within this report. One may argue and prefer a narrower definition of market as the meeting of many suppliers and consumers, with none large enough to influence the final clearing price, i.e., none having "market" power. Unfortunately, a narrow definition would make it impossible to describe the situation when demand and supply are in balance, whatever the numbers of actors, and the way the price is determined (e.g., higher prices may create a lower demand that will be supplied by a monopoly or oligopoly).

The starting point of the energy market reforms in the USA was the publication in 1978 of two major laws: the PURPA (Power Utility Regulatory Policy Act) and the NGPA (Natural Gas Policy Act). Regarding the PURPA, the USA utilities at the time were under tariff regulation. The main purpose of reforms was to increase competition by allowing the entry of private generators, but within guidelines for technologies such as CHP and with obligations for the host utility to purchase the output[64]. There was increased access, but it was not on competitive terms, since the purchase was based on pre-defined tariffs.

In Europe, gas use in power generation was forbidden until the 1990s, when CHP was encouraged through competitive tenders, but as in the USA, with prices under public control.

NGPA started the progressive freeing from price controls of the new "vintages" of gas production. New wells were first liberalised[65]. Then, progressively, older vintages of gas wells that had had their prices controlled since the 1950s were allowed to sell at "liberalised" prices. In practice, these new prices were higher than the level of "competitive market prices" because of the possibility for marketers to blend old regulated gas and new deregulated gas and sell it at the weighted average price. Since the average price was that set by the competition with petroleum products, and the price-controlled "old" gas was much cheaper, it came as no surprise that the new gas was sold at higher than market prices, up to $10 /MBtu at the beginning of the 1980s.

For the purposes of this report, whatever the balance of supply and demand and the external influences on them or on the clearing price, this is a market. *Energy Market Reforms* therefore covers any reform which makes the former "market" work more efficiently for the benefit of all. Liberalisation will mean that new actors have the right to access some parts of the "market" that were not previously available for entry. Privatisation will mean that either the ownership or the

[64] Economies of scale in CHP do apply, in that building "over-sized" production units is more efficient, but if the fuel source is not cheap enough, this will be discouraged. This explains why electricity reforms and natural gas reforms need to go hand in hand. In the UK, as in the Netherlands (NL), the issue of the pricing of gas proposed to the co-generators was based on the competition with heating oil by BG or by Gasunie respectively, as it is the case for the residential, commercial and small industrial consumers of gas monopolies. This was challenged by the developers of CHP, and they finally got a heavy fuel oil parity, as for large industrial users, in the two countries. In the UK, this issue became irrelevant once the MMC (Monopolies and Mergers Commission) obliged BG to release gas and the producers to sell at least 10% of their new gas to marketers other than BG because these actions gave birth to a level playing field thanks to the development of the spot natural gas market. The attractiveness of natural gas was further increased after 1995, when the spot price of gas fell to 10-12 p/therm ($1.5-1.8/MBtu), similar to the marginal price of imported coal. In NL, the pricing of gas at parity with large industrial users was mandated by the government for the sake of efficiency and reduced overall GHG emissions.

[65] For Japan, full liberalisation may be defined as "the state in which all customers have choices of suppliers" and may not be equal to unbundling. Japan would say, "As far as a competitive market is assured in the supply sector, unbundling the incumbent power companies is not necessary". The WEC Regional Forum in Tokyo in 1999 was the first to coin the phrase "partial liberalisation" to describe developments in the Japanese market.

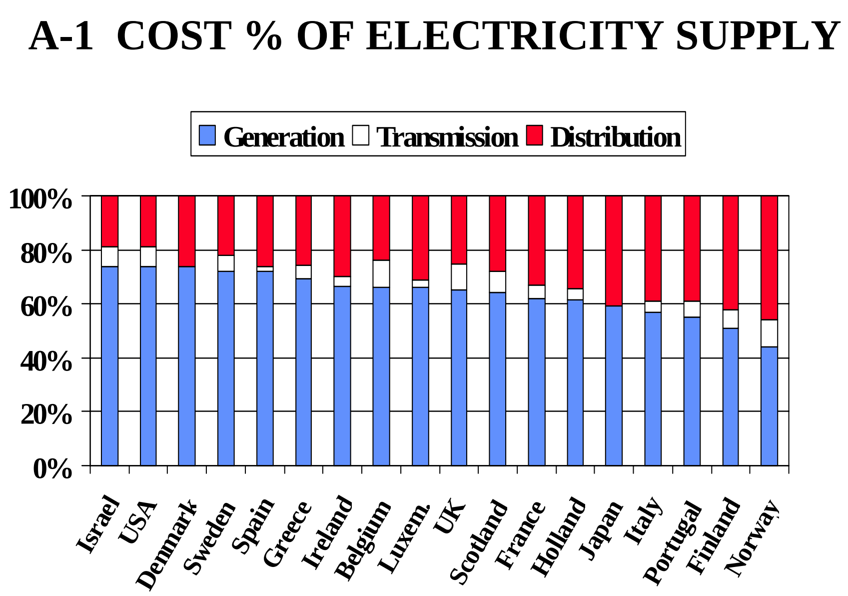
management of the activity goes to the private sector, with rules akin to competition. For the latter, the word "corporatisation" will also be used.

## 2. The Parts of an Energy Network (Electricity and Natural Gas)

One needs to consider the infrastructure (generation, transmission, distribution) and the commercial links (wholesale & retail supply, and trading).

For electricity services, the following graph[66] (courtesy of IEA, John Paffenbarger) shows the three main components of the infrastructure (see definitions below):

- Generation (50 to 70% of the total costs)
- High voltage transmission (about 5% of the total costs)[67]
- Distribution (20 to 40% of the total costs[68]).




*Source: IEA (after John Paffenbarger)*

For natural gas services, the wellhead price of domestic gas or the border price of imported gas represent a smaller share of final energy service costs than generation does for electricity, say, about 40%. Since it is often impossible to "generate", i.e., produce gas locally, this leads to the paradoxical evidence that gas is transported over long distances and that, even within a country, the share of high-pressure transportation costs is higher than for electricity, say, 20 to 30% of the total costs. The share of distribution costs is high, as for the electricity sector, say, close to 50% of the total costs for the captive residential and commercial customers.

Unbundling

Definition of the "market" is further complicated by the fact that energy networks aggregate several different activities, which are presented in the following paragraphs. In the traditional monopolistic utility structure, these activities were managed simultaneously. However, reforms introduce some elements of freedom that will affect only certain activities. Hence the question of unbundling the

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[66] Recent information provided by the Japanese utilities provides the split of the 40% that are not generation costs. High voltage transmission costs represent 19% (cost of land, seismic risk, mountains) and distribution costs 21%.
[67] Transmission costs may be as high as 10%, depending on the content and state of development of the country.
[68] If one were to focus on the captive residential and commercial sector, the share of distribution costs would be higher, close to, or sometimes higher than, 50%.

different network activities. This question lies at the heart of the energy market reforms and depends on the degree of reforms and the number of separated “markets” they create.

**3. “Upstream” Sector**

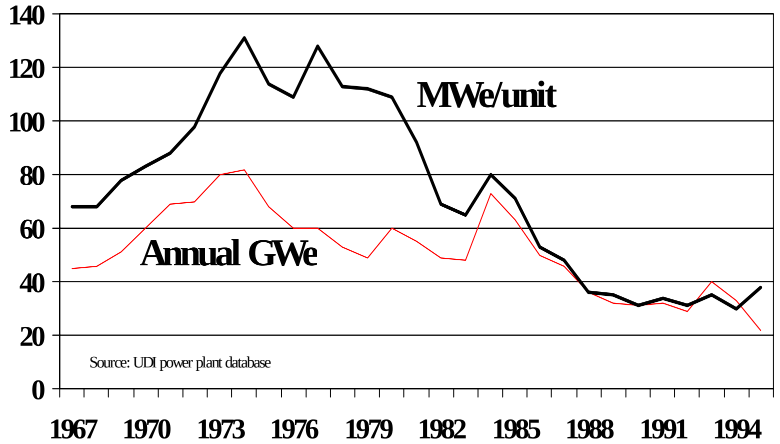
For electricity, this covers domestic power generation and imports as well as the wholesale[69] market. External boundaries of the system were traditionally national or even smaller in large federal countries (for instance, utilities were designed at state level in the USA, a situation that still holds for Texas even though other states now choose to gather in regional organisations).

Economies of scale since the end of WWII have favoured the creation of large power plants -- up to 1 GW and more -- that deliver their electricity to the high voltage power transmission grid (say > 130-150 kV). However, since the 1980s and 1990s, the emergence of diseconomies of scale for the CCGTs (combined cycle gas turbines), especially for industrial (and now commercial) combined heat and power systems, has created a new wave of non-utility generators that may sell their power directly to the distribution companies, but generally do not (e.g., for quality reasons [reactive power]).

The figure below (courtesy of John Paffenbarger [IEA]) is based on the UDI data. It shows that the average unit size at world level increased up to the first oil shock in 1973, reached a maximum between the two shocks (average value of about 120 MW) and has since declined to its present average 30 MW size. Total annual capacity additions rose sharply from 40 (mid 1960s) to 80 GW (1973), remained high at about 60 GW per year up to 1986 and have been since falling (30 GW presently).

The high deliveries up to the mid 1980s are the consequence of the lead times required to build the new units. The launch of new capacities accelerated after the first oil shock of 1973 with the aim of diversifying out of oil and only stopped after the second oil shock in 1979-80 when it became evident that the new plants under construction were exceeding by far the new, much lower forecasts of demand growth. However, these new plants, because of their, say, six years, construction time, continued to come on stream up to 1985. In addition, new small plants came on stream in the early 1980s because the new USA policy defined by the PURPA of 1978 allowed the building of non-

**A-2 DECREASING OECD SIZE**




*Source: IEA (after John Paffenbarger)*

[69] Generation and wholesale markets may be separated when strong transmission constraints exist.

utility "qualified facilities".

In short, the emergence of diseconomies of scale at a time when all OECD electricity systems were exhibiting large over-capacities was a, if not the, driver for market reforms. The causal sequence of events that started at the end of the 1970s was the following:

- The building of new plants to diversify out of oil after the oil shocks because of the sharp increases of heavy-fuel oil prices after 1973 and 1979;
- The recessions (1974-75 and 1980-82) and economic slow-down (from the high figures of the "golden 1950s and 60s" to the lower figures of the "crisis" of the 1970s and 80s) that led to a sharp drop in the average electricity growth rates; leading to
- A gap between the growing capacities and the lower demand with the large and costly over-capacities attributed to the inefficiency of former monopolies (even though a competitive system would have made no difference);
- This inefficiency in turn justified the reforms and the new reliance on qualified facilities that were not controlled by the incumbent utilities.

For natural gas, "upstream" covers domestic production and imports as well as the wholesale market[70]. Domestic production, be it non-associated gas (i.e., flowing from "gas" wells) or associated gas (i.e., flowing with oil from "oil" wells) is sold directly to the high-pressure transportation grid, which fulfils the quality requirements (Btu content, composition, etc.). Natural gas can also be imported via pipelines or as LNG (liquefied natural gas) from outside the national boundaries. Whereas electricity is even now a state affair in the USA, natural gas became an intra-state matter very early (before WWII). Today, intra-state and interstate infrastructures and legislation coexist.

## 4. "Midstream" Sector[71]

For electricity, as suggested by its name, this is the sector between the upstream sector that provides the bulk supply to the large customers, be they individual industrial customers or collective distribution companies. It is mostly the high voltage (say, above 130 kV) grid. It represents only a small share of the total costs, 5% on the average through a range of countries.

Ancillary services[72] are traditionally associated with the management of the HV grid[73]. They include a number of technical services that are better managed centrally, such as reactive power management and the stability of voltage and frequency.

For natural gas, midstream is mostly the high pressure (say around 70 bars) transmission pipeline network but also includes some ancillary services aimed at keeping the pressure high enough to avoid air entering distribution lines, respecting the properties of the gas stream (calorific values, dew point, etc.), and managing storage facilities:

- Either upstream storage facilities to ensure the regularity of the flow in the transmission grid (therefore located close to the areas of production, e.g., Texas, Louisiana and Oklahoma in the USA). This is true as long as the supply is not unbundled from transportation. If unbundled, management responsibility goes to the wholesale suppliers.

[70] For electricity, when strong locational differentials exist, it may be more convenient to associate the wholesale market to the management of the high-pressure grid.
[71] Large users that are directly supplied from the HV-transmission or HP-transportation grid are not, according to their connection, part of the downstream sector, whereas for local distribution companies (LDCs) which are also connected to the grid at the "city gate", their customers depend on the LV and LP grids of the downstream sector.
[72] The importance of ancillary services differs greatly between fossil-fired stations and hydro-dominated markets such as Nordpool, where ancillary services have no value.
[73] "System operation" in a control area is a key activity, alongside transmission and ancillary services.

- Or downstream storage facilities to smooth the supply-demand imbalances at the consumer level (therefore located close to the consumption areas, e.g., Midwest and Northeast in the USA). Regular seasonal swings are provided by former oil and gas reservoirs or aquifer reservoirs and rapid random variations by salt caverns or aerial reservoirs. These facilities are generally under the control of the distribution companies as long as retail supply remains bundled (and by suppliers in case of unbundled supply).

In terms of midstream infrastructure, while high-voltage transmission only represents 5% of the total average cost of electricity, it represents 10-20% for natural gas for the national high-pressure gas grid, at least another 10% if one includes the storage and much more if one includes international pipelines such as those that supply Europe from Norway, Algeria or Russia. Such high costs compared to those of the electricity transmission grid may seem paradoxical, but the basic reason why gas is cheaper to transport is the much lower level of losses or auto-consumption. This is the very reason why electricity is not transmitted over long distances (and when it is, one must use DC lines) whereas natural gas is.

## 5. Regulatory Authorities

Market reforms create new systems that need to be regulated either by specialised authorities (because of the peculiar nature of energy network industries) and competition/market authorities ensuring that transactions are conducted in good faith, or only by the latter (the case of Germany so far). In that respect, there are several models that depend on the historical legacy of the country.

The US model emerged during the 19th century with the main features of a regulation based on public interest (Munn's case in 1870) and the progressive rise of anti-monopoly legislation. The "Commissions" appeared as the first regulatory authorities at the end of the century. They are:

- Independent (immovable members) at state or federal level;
- Working as colleges;
- Hybrid (executive, legislative and judicial power);
- Nominated by the executive branch but countersigned by legislative authorities;
- Entitled to overlook, inquire, control and intervene.

The UK model was born in the early 1980s as a response to the wave of liberalisation and privatisation of the time. Its characteristics are the following:

- Independent and immovable regulator to avoid conflicts of interest with other state policies;
- Individual regulator with personal responsibility;
- Regulator nominated by the executive branch;
- Possibility of appeal to the MMC competition body (Mergers & Monopolies Commission).

The UK model was recently modified by the merging of the gas and electricity regulators and by the explicit reference to the priority to be given to the customer for energy services.

More generally, these two "models" play a key role, either as a direct reference, or as a means to categorise all other models in terms of the two principal variables: the definition of the regulatory missions and the institutional architecture (between the state -- legislative and judicial framework, the government -- executive rulings and the regulatory authorities).

Regulatory uncertainty is a new concern. Regulatory changes may have sound reasons, in particular the fact that regulators, having less information on what the true costs are than the market actors, need to adapt their yardstick rules when they discover that actual costs are lower than what they initially anticipated. However, for the market actors, such changes are akin to regulatory uncertainty, and increased uncertainty means increased risks that boil down to increased costs. This "quis custodiet ipsos custodes?" ("Should regulators be regulated?") question was discussed in the

November 2003 World Energy Regulatory Forum in Rome and has an even greater relevance in the developing countries because the perceived risks are generally higher than in mature economies. This new concern about the stability of energy regulations explains the May 2003 World Bank proposal, "Regulation by Contract: A New Way to Privatize Electricity Distribution?", the purpose of which is to reduce the regulatory risk in developing countries.

In this context, "regulatory independence" should be understood as the absence of interference from the political world, but not as a free ride without control. As suggested by the World Bank, the concept of a "regulatory" contract may be a good way to balance the benefits and risks of "independence".

## 6. Key Design Options for Regulatory Agencies

The table on the following page summarises the different domains covered by regulation, the design issues and the key options. It is extracted from the report of the meeting, "Regulation of Energy Industries", (03/09/2001 - A cycle of conferences co-sponsored by the French Planning Commission and the Directorate General for Energy and Raw Materials) prepared by M. Maheu.

## 7. Specialized Energy Regulation or Competition Authorities?

While the problem is less acute in the USA because their long tradition of regulation has contributed to the development of formal/informal cooperation overlooked by the law, Europe still suffers from the absence of duality between specialised energy authorities and competition/market authorities. Competition is the joint responsibility of the Directorate General for Competition in the European Commission and the Luxembourg Law Court, but energy regulation only exists as an informal coordination, either as a closed loop of the European regulators or between the Commission and the regulators. In addition, at the sub-national level, all models are possible in terms of the sharing of competences between the two respective extreme cases of the French centralised model and the German combination of federal, regional (lander) and municipal levels.

Hence there is no simple answer to this question, but the following elements may be proposed:

- In favour of competition authorities: A significant part of the analysis of market reforms relates to the problem of market power. Other issues may seem of critical importance in the early stages of market reforms but lose their importance once the system has become mature. This is why some experts or countries (Germany) tend to favour the choice of market authorities to control electricity and natural gas networks and have not been keen to create specialised agencies.
- In favour of regulatory agencies: They largely work ex-ante, whereas market authorities work ex-post. The greater certainty of an ex-ante regime (to the extent that there is a real regulatory stability, an as yet unproved approach in Europe) has a value to customers and shareholders alike. Another argument is the technical specificity of energy networks that require a high degree of expertise[74] from the authorities.
- Last, but not least, this issue seems to be more about the form of public intervention (which ex-ante regulations?) than that of the institution that regulates[75]. In particular, existing market authorities have the benefit, by design or thanks to some jurisprudence established over time, of well defined interfaces with the executive (government) and the judicial parts of the state.

[74] In addition to the specific nature of electricity or natural gas, arguments in favour are the number of technical questions that need to be solved (definition and provision of ancillary services, identification of market power, specific political interfaces for security, diversification of the primary fuels, environment, social goals), the more so when there are conflicts among them. All these questions had an impact in the cases of California and Taiwan.

[75] The arguments of Germany to rely on the Bundeskartellamt (anti-trust authority) may be of this nature, but this goes beyond the straightforward question of the national level because of the need to also ensure consistency at the trans-national level, e.g., within the EU or within federal states such as Australia (where it still is a problem), Canada or the USA (where, since the end of July 2002, the matter has been under a FERC proposed regulation).

| Key Design Options for Regulatory Agencies (source: bibliography) | | |
|---|---|---|
| ***Area*** | ***Design Issue*** | ***Key Options*** |
| ***Mission*** | Objectives | One or several among:<br>- consumer protection<br>- investor protection<br>- economic efficiency<br>- competition advocacy |
| | Jurisdiction (powers) | Regulatory powers only or, additionally:<br>- mergers<br>- other competition law<br>- policy on entry, investment, privatisation |
| | Industry coverage | One industry (ESI) or multi industry |
| ***Governance*** | Decision-making structure | Single regulator or commission<br>Odd or even number of commissioners<br>Staggered terms or not |
| | Appointment of regulators | Made by parliament or by government<br>Stakeholders allowed or not<br>Based on professional competence criteria or not |
| | Independence safeguards | Irrevocable mandates<br>Prohibition of conflicts of interest during and after mandate<br>Stable funding |
| ***Regulatory activities*** | Functions | One or several among :<br>- regulation of monopolies<br>- end-user tariffs and quality standards<br>- monitoring<br>- dispute resolution<br>- advisory role to government |
| | Process and appeals | Process based on :<br>- rule-making<br>- negotiation among stake holders<br>- monitoring and remedial action<br>- rules to promote transparency of decision-making such as hearings and publication of decisions<br>- designation of an independent appeals body or not<br>- grounds for appeal restricted to complaints on undue process or not |
| | Coordination with other authorities | Formal or informal mechanisms for consultation and referral |
| ***Resources, management and external control*** | Funding | Earmarked or not<br>From state budget or from industry<br>Size<br>Stability of time horizon |
| | Human resources | Salaries at market levels or subject to civil service rules<br>Competence and specialisation of staff<br>Use of external resources |
| | Reporting and auditing | Reporting to parliament, line ministry, other ministry<br>External audits |
| ***Transition issues*** | Start-up strategy | Timing: set up before or after reform<br>Initially, staff on secondment from industry or ministry allowed or not |

## 8. "Downstream" Sector

This is the sector that is close to the end-users; it includes the "distribution" i.e., the physical component or "hardware" part of the downstream business (low-voltage, low-pressure grids that feed the "small" residential and commercial consumers). The commercial or "software" part of downstream (retail supply, associated metering and billing services to the small consumers) is discussed in the following paragraph. Distributed energy for the customers of the distribution grids is not a pressing issue yet. It does not exist for natural gas any more, since natural gas has replaced town gas. However, it might become a concern for the electricity distribution when small CHP or tri-generation (providing power, heat and cooling) or fuel cells become available for the commercial residential sectors.

Large industrial consumers are directly fed by the high-voltage, respectively high-pressure grid, thus making distribution companies a specific (because of its captive market) "large" user directly connected to the high-voltage transmission or high-pressure transportation grid as long as the supply of their customers remains under their responsibility.

A key issue is the definition of the border line between high-voltage transmission (respectively high-pressure transportation) and low-voltage (respectively low-pressure) distribution. Such a border line does not exist in certain markets (e.g., Transco in the UK manages the totality of the gas grid), and when it exists, it may include several discriminating parameters in order to split between the "wholesale" customers and the "captive" customers or among the captive customers to create several independent local distribution companies (LDCs):

- The voltage (say, above 130 kV);
- The annual consumptions (say, above 100 MWh);
- The numbers of customers within a local distribution company (see below);
- The acreage covered by a single LDC;
- But also some other parameters such the density[76].

For the sake of internal consistency, this report will assume that transmission and distribution are clearly separated and that distribution itself is split into smaller entities called "local" distribution companies (LDC) with "local" meaning ranging from "national" (UK TRANSCO for natural gas even though the creation of regional entities is under discussion) or "regional" (UK regional electricity companies) with, say, five million customers or more, to really "local" (group of small municipalities or large cities or parts of very large cities), with, say, a few hundred thousand customers maximum.

## 9. Supply

Whereas "upstream", "midstream" and "downstream" are associated with a physical part of the energy system, supply is a concept that goes through these three sectors and reunites them. Not only is supply a global concept, but it also starts from the end-users, i.e., the demand for the provision of the right energy service at the right time before becoming what is usually called "supply", i.e., the provision of electricity or natural gas by the upstream sector.

In the former integrated utilities, "supply" was not identified as such because it was totally integrated into the management of the three sectors. In a system open to competition and partially or totally unbundled, it becomes the key issue that will in turn influence the management of the three physical links.

[76] Small geographical monopolies may cause serious NIMBY ("not in my back yard") issues. In the case of Japan, Niigata and Fukushima prefectures belong to Tohoku Electric Power but are the major power sources of TEPCO thanks to three nuclear power stations located in these two prefectures. Hence there is the complaint that the power generated in their territory is sent to Tokyo and does not benefit the region. In a similar way, if TEPCO distribution were to be divided into smaller LDCs, residents within one LDC monopoly area could complain that their supply originated in other regions. For example, Chiba prefecture, where about 60% of TEPCO thermal generation facility is located, may claim the same kind of argument, whereas, conversely, some suburban prefectures may complain about the siting of transmission lines.

**ANNEX D**

## COMPLETING THE INTERNAL ENERGY MARKET: THE MISSING STEPS

***Statement of the Council of European Energy Regulators in Rome, October 6, 2003***

1 . In the old days of national monopolies, energy utilities were under Government's "command and control". The benefits and costs of this approach were supported by consumers and utilities according to national criteria. Cross-border energy trade was limited to wholesale transactions among incumbent utilities, cross-subsidies between different groups of national consumers were tolerated, some utilities were subsidised while others were not sufficiently remunerated. Since there was no competition among utilities and no choice for consumers, national decisions had no direct impact upon utilities or consumers in other countries.

2. Directives 96/92/EC (electricity) and 98/30/EC (natural gas) established the legal basis for the Internal Energy Market. Millions of eligible consumers are already free to choose their electricity or natural gas supplier in any Member State of the European Union. Energy undertakings are free to trade and to invest in all Member States. This means that national energy systems are now open. Political, legislative or regulatory decisions concerning energy investment and trading frameworks in one Member State have a potential impact upon all Member States. Acquisition, investment or trading decisions by one energy undertaking have a potential impact upon all EU energy markets. However, the Internal Energy Market is still far from being a reality.

3. The Internal Energy Market provides new opportunities to energy consumers and to energy undertakings. It has the potential to increase economic and technical efficiency, as well as security of supply, thus improving European welfare and the competitiveness of European industry. It can also be an important tool to reinforce political and economic links with Eastern European and South Mediterranean countries, thus contributing to stability and development in these areas.

4. If the Internal Energy Market is not properly organised, and if the increasing interaction between national political, economic and institutional decisions is not duly taken into account, it may engender inefficiencies, leading to high energy prices and poor quality of service and even endangering security of supply.

5. Completion of the Internal Energy Market is a complex and relatively slow process. It is strongly influenced by the different speeds of national legal, institutional and industry developments. The present stage of the Internal Energy Market is a critical one. It is the duty of energy regulators to point out the present difficulties and to suggest appropriate solutions leading to fair, efficient, secure and integrated energy markets in the European Union.

6. The five major factors hindering the fast development of a single energy market may be grouped into the following categories:
   a) Lack of transmission capacity (in particular, cross-border interconnection capacity).
   b) Lack of transparency in network access conditions (including network access tariffs and congestion management).
   c) Lack of transparency in the technical operation of interconnected systems.
   d) Lack of robust, deep and liquid organised energy markets in most geographical areas.
   e) Lack of transparency and predictability concerning rules applied to the approval or refusal of mergers and acquisitions in the energy field.

7. Transmission capacity, in particular cross-border interconnection capacity, is essential for the development of efficient energy trade and for increasing security of supply. While a few new

interconnections are under construction and the European Council requested electricity interconnection capacity to be substantially increased by 2005 (up to, at least, 10% of the installed production capacity in each Member State), five main problems remain:

a) Administrative procedures are too lengthy and sometimes prone to political interference, leading to unreasonable delays and even, in some cases, to project cancellation.
b) The allocation of interconnection capacity to long-term contracts between utilities reduces the available commercial capacity in some areas.
c) Vertically integrated utilities usually have no interest in developing new interconnections.
d) Special regimes applied to the construction, operation and use of merchant lines may reduce the commercial capacity available to network users in general and discourage the expansion of public networks.
e) Some degree of coordination among those responsible for transmission network planning and construction is necessary if "patchwork" solutions are to be avoided.

Recent initiatives from the European Commission related to energy infrastructure recognise some of these difficulties and will lead to suitable solutions.

A clear and integrated map of transmission capacities available and under construction in Europe is urgently needed, both for electricity and for natural gas.

8. Transmission networks were not developed in order to support efficient trade. Distribution networks were not developed in order to support the efficient integration of decentralised generation into the electricity system. Therefore, network planning - and not only interconnection planning - must be adapted to the new requirements, in order to ensure quality and security of supply under new market and environmental conditions.

9. Transparency in network access conditions must be improved in order to ensure fair treatment of all network users, independently of their size, nationality, contractual arrangements or ownership.

   Trust in the independence and non-discriminatory behaviour of Transmission Systems Operators (FSOS) is strengthened by their full separation from any other interest in generation, trading or supply. Ownership unbundling, although introduced in an increasing number of Member States, is not yet fully applied. This situation is particularly worrying in those countries where independent energy regulators have not yet been appointed (Germany and even more Switzerland).

   In order to ensure non-discrimination, network access tariffs must be fully cost-reflective. Cross-subsidies between different activities (e.g., transmission and generation in vertically integrated undertakings) or between different groups of consumers (e.g., low-voltage and high-voltage) result in harmful distortions of competition.

   The recent Regulation (EC) no. 1228/2003 of the European Parliament and of the Council on conditions for access to the network for cross-border exchanges in electricity lays down basic principles with regard to tariff-setting and capacity allocation. Regulatory authorities and the European Commission will cooperate in order to ensure appropriate compliance with the regulation and full transparency.

   As a consequence, from 2004 on, access to electricity networks will be more transparent throughout Europe. A similar regulation for natural gas is needed.

10. Transparency of network access and efficiency of network operations is better ensured when the TSO is also the owner of all relevant transmission assets.

11. Technical coordination among TSOs is essential for the proper operation of the interconnected electricity and natural gas systems. Lack of coordination has two major drawbacks - it may:

    - Jeopardise reliability and security of the interconnected systems;
    - Limit the commercial freedom of network users beyond strictly necessary levels.

    The technical rules, procedures and criteria governing operation of the large interconnected EU energy systems have to be adapted and rewritten, taking into account the complexity resulting from the increasing number and diversity of commercial transactions taking place nowadays. They shall be prepared by the TSO, approved by regulators (since they may have impact upon costs and competition) after extensive consultation of all stakeholders and made public; review procedures shall be transparent and known in advance.

    Following CEER request at the Electricity Regulatory Forum in February 2002, European TSO associations are working towards the definition of a comprehensive set of common security and reliability standards. Similar efforts should be developed by natural gas TSOS.

12. The step-by-step completion of the Internal Energy Market requires the increasing convergence of regional markets. However, in some regions organised energy markets still do not exist and in other regions the existing markets are not robust, deep and liquid enough. The design and implementation of efficient energy markets (electricity and gas) in Europe should be a high priority. Well functioning markets must also provide appropriate risk management instruments: in a market environment, vertical integration is not necessarily the most efficient mechanism.

13. Moving from national monopoles to EU electricity and gas markets requires important adjustments to the present energy industry structure. EU energy markets cannot function properly without a reasonable number of energy undertakings selling their products and services in several Member States. Restructuring of the energy industry will bring more innovation and more efficiency to energy markets. Therefore it is important that national governments and competition authorities cooperate among themselves and with the European Commission in order to implement a coherent policy regarding the approval of mergers and acquisitions, as well as the assessment of market power. Energy regulators have signalled their will to cooperate toward this common goal.

14. The recent Directives 2003/54/EC (electricity) and 2003/55/EC (natural gas) provide a clear framework for completing the Internal Energy Market. The way forward was jointly defined by the European Parliament and by the Council.

    The CEER will work with the European Commission, in close cooperation with all relevant stakeholders, in order to ensure that the Internal Energy Market, through appropriate regulation, will fulfil consumer expectations in terms of price, quality and security of supply.

15. Recent, unrelated incidents that affected many electricity consumers in Europe may be the consequence of some factors described above which hinder the development of a single energy market. They are <u>not</u> a consequence of liberalisation and integration of European electricity market. These problems have been identified, as well as their respective solutions.

    Some people believe that the Internal Energy Markets magnifies the risks and reduces opportunities. The CEER thinks the opposite is true. Therefore, we will endeavour to complete the Internal Energy Market as soon as possible, according to the mandate which was given to us by the Member States, by the European Parliament and by the Council. The CEER is working towards the completion of the Internal Energy Market to ensure that European consumers obtain the full benefits of liberalised markets as well as secure supplies of energy.