ESMAP

Joint UNDP / World Bank **Energy Sector Management Assistance Programme**

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Impact of Power Sector Reforms on International Electricity Trade

March 1996

Power Development, Efficiency &
Household Fuels Division
Industry and Energy Department
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Consultants Report

prepared by

London Economics

March 1996

Project supported by the United Kingdom's Overseas Development Administration (ODA)

Contents

Abbreviations and Acronyms

AGC	Automatic generation control
AC	Alternating current
BPC	Botswana Power Corporation
CEGB	Central Electricity Generating Board (UK, pre-privatisation)
DC	Direct current
EGAT	Electricity Generating Authority of Thailand
ESKOM	Electricity Supply Commission (of RSA)
GWh	Gigawatt hour (1,000,000 kWh)
HV	High voltage
HVDC	High voltage direct current
IOPC	Interconnection Operating and Planning Committee
ICS	Interconnected system
IPP	Independent power producer
kW	Kilowatt
kWh	Kilowatt hour
kV	Kilovolt
LRMC	Long Run Marginal Costs
LV	Low voltage
MV	Medium voltage
MWh	Megawatt (I,OOOkW)
NEPEX	New England Power Exchange
NEPLAN	New England Power Planning
NEPOOL	New England Power Pool
NERC	North American Electricity Reliability Council
NHPC	National Hydropower Corporation
NTPC	National Thermal Power Corporation
REB	Regional Electricity Board
RLDC	Regional Load Despatch Centre
RSA	Republic of South Africa
SADC	Southern African Development Community
SAPP	Southern African Power Pool
SEB	State Electricity Board
SNEL	Societe National d'Electricite du Zaire
SRMC	Short Run Marginal Costs
ToR	Terms of Reference
TNB	Tenaga Nasional Berhad
TWh	Terawatt hour (109 kWh)
UCPTE	Union pour la Coordination de la Production et du Transport de l'electricite
UPS	Unified Power System (of former Soviet Union)
ZESA	Zimbabwe Electricity Supply Authority
ZESCO	Zambia Electricity Supply Corporation
ZCCM	Zambia Consolidated Copper Mines

Foreword[1]

Summary: ***Development of international electricity trade will be a direct consequence of the ongoing and worldwide power sector restructuring efforts. Vertical unbundling liberates the distribution function from tied production and unlocks the transmission bottlenecks. Horizontal unbundling promotes competition at production and distribution levels for the benefit of the final consumers. A direct consequence of such restructuring is the search for the cheapest way to access electricity, including imports. However, in many countries, electricity is still considered a strategic good, and full liberalization of trade depends on the legal and regulatory structures of potential partner countries. Therefore, international interconnections have been often limited to the search for more reliability, or to long-term bilateral contracts for firm energy. However, recent sector reform efforts around the world are prompting a new look at trade issues.***

Overview.

1. International trade of electricity between countries is not new. The search for better reliability, reduced production costs and improved quality of service were the driving forces for the interconnection of small independent systems. In this context the accumulated successful experiences fostered further development of many regional and international interconnections.

2. Up to recent years, most electric utilities around the world were vertically integrated entities performing simultaneously the three primary functions of generation, transmission and distribution. Most of them were more or less self-sufficient in terms of generation in their respective geographical areas. Interconnection with neighboring countries were mainly developed to reduce the level of reserve capacity and to benefit from complementary means of generation where hydro-electricity has played a major role or from load diversity or maintenance scheduling.

3. The challenges facing today's electric utilities are greater than ever. Unbundling of functional activities and the search for better efficiency in technical and managerial operations for heightened competition, present new opportunities and a whole set of obstacles and risks.

4. The present report, prepared by London Economics with Terms of Reference written by ESMAP, and with the financial support from UK-Overseas Development Administration (ODA), focuses essentially on the lessons that could be drawn from institutional and economic experiences accumulated within different regional networks including:. the Nordic countries (NORDEL), the Western European countries (UCPTE),

[1] Prepared by ESMAP.

the England/Wales-Scotland interconnection, a regional interconnected system in India, different US pools: the "tight" pool of the New England area (NEPOOL) and the "loose" pool of the Mid-Continent Area Power Pool (MAPP) as well as new areas where a regional interconnection is under consideration or development such as: .the Southern African Power Pool (SAPP in the SADC region), the East Asian countries of the Mekong valley and the four countries (Argentina, Brazil, Paraguay, and Uruguay) of the Mercosur area in Latin America.

5. This report draw heavily from a previous study also undertaken with London Economics and titled:" Development of Regional Electric Power Networks" published in October 1994. This first study found a closed link between power sector reform and the development of electricity trade which studied in more details in the present report.

6. The findings and lessons learned are detailed in the report. Key features can be underlined as follows:

Technical standards

7. Development of trade requires an adequate structure of interconnectors and is facilitated by compatible technical standards. The stability of an interconnected regional network requires adoption of technical standards acceptable by all traders. In this regard, the implementation of pooling arrangement will facilitate trade.

8. However, technical constraints can be overcome at a price. Asynchronous connection does not allow all the benefits to be captured, but does save the cost of enforcing the common and detailed technical standards required for successful wide scale AC connection. Between technically compatible systems and for relatively short interconnection lines, preference is given to synchronous connections. These are generally the most economical means of interconnection. This required, however, rigorous technical cooperation and trust to avoid cascading failures. Between systems or countries which are not operating at the same level of technical standards, "back to back" DC interconnectors are used to avoid the transfer of technical disturbances from one network to another. For the transport of large amounts of energy over long distances, DC lines are generally preferred for economic reasons.

Institutional and Organizational Framework

At National Levels: Unbundling and Third Party Access (TPA)

9. Harmonization of power sector structures between interconnected countries facilitates the understanding among the parties and consequently is an important favorable factor for the development of trade. The case of the NORDEL countries serves as an

illustration. The unilateral reforms implemented in Norway originally affected drastically the electricity exchanges between the countries of the network and especially with Sweden during some time. Trade resumed again and even expanded upon implementation of a similar reform framework in Sweden.

10. International trade of electricity may expand with the worldwide ongoing restructuring effort of the power sector. Unbundling of generation, transmission and distribution could stimulate distribution companies to look for attractive supply conditions wherever the source of production: at national or international level.

11. Vertical separation introduces greater transparency into system operations. Horizontal separation enables clear competition between generators. Furthermore, regulated third party access (TPA), under which the grid owner must give access, on reasonable terms, is paramount to the development of competition and to the development of trade.

12. However, creating effective competition between generators is difficult where one or a few hold significant market power. Trade and where possible a joint market place across borders, can reduce the power of a large generator while leaving economics of scale untouched.

At Regional Level.: Pooling and Regional Transit Agreement.

13. Bilateral or limited trade of economy energy do not require sophisticated arrangements. For larger amount of short term energy and capacity trade, Government support may play a driving role, particularly in the case of Government owned utilities. Development of intensive regional trade could be boosted by pooling arrangements including transit (i.e. wheeling) agreements. Where pooling arrangements are set in place, appropriate management structures are required and voting rules should ensure high degree of consensus on the operation of the pool.

14. Transport of electricity, sometimes through various borders, remains a major bottleneck. Three major conditions seems to be required to overcome this. Firstly, transmission should only be a "service" with a specific tariff structure independent from energy prices. Secondly, as transmission will remain a monopoly within given areas, it should be regulated and international agreements should be discussed between different concerned countries so that the transmission regulatory regimes include an international transit (i.e. wheeling) clause. Thirdly, some sort of international coordination between the dispatching centers of the different transmission companies must be put in place to ensure the technical feasibility of such international transfers of electrical energy.

15. Regional transit agreements as well as third party access (TPA) are conditional to the enhancement of a regional competitive trade structure.

16. In Western Europe for example, the European Union has already published "Transit Directives" whose purpose are to facilitate the mandatory transit of electricity between the different countries for the whole region.

17. Open access to transmission networks is a necessary condition for effective competition and is a key feature in the development of regional trade activities.

Regulation

18. Regulation of generation and transmission access are relevant to cross-border trade. Regulation in generation is reduced where competition in bulk generation is effective. However regulation is required to ensure access to the transmission network so that trade is not physically constrained.

Pricing principles: Bulk Electricity and Transmission Services

19. The main approach to electricity was based on the avoided costs/split the saving principles which was expected to provide a "fair" price to both parties. The cost of such an approach grows as the complexity of trade increases. If trust between the two parties diminishes, -for example, following a change in ownership,- the costs are also likely to grow because of greater requirement for verification.

20. A more recent approach for price setting relies on the basis of generator bids based on marginal cost, as in Norway, England, Chile and Argentina. Marginal cost based pools provide far more information on system marginal price at different periods and provide a mechanism for selecting the cheapest generators.

21. Irrespective of the approach, it is important to agree tariffs before investments proceed.

22. Approaches to energy, capacity and transmission pricing vary. Problems on energy pricing arose mostly in the transition from one price system (or no pricing system) to another. The pricing of firm power was not always structured to gain the most benefit from capacity. In most of the studied cases, transmission was not unbundled or separately priced. This did not appear to be a constraint to trade in the case of the limited exchanges done by integrated companies. However, if power sector reform proceeds, then transmission pricing could become a constraint to trade in absence of transparent tariffs for transmission services.

23. Transmission pricing can affect dispatch. Vertical separation of transmission price with transparent and well formulated pricing structures, will certainly promote generation efficiency and trade where economic.

24. However, several transmission pricing structures are possible. Therefore, inconsistent transmission pricing between countries can be a major obstacle to the development of trade.

Contract and contract enforcement

25. The sophistication of trading contracts will depend in part on the ability to monitor the trading arrangement. Trade will not develop if contracts cannot be enforced, ensuring reliable payment. Present contracts cover the supply of energy and transmission services. They can be short term, affecting dispatch decisions by the purchaser, or long term and also affect investment decisions. If they are incorrectly structured, they will not give incentives for optimal dispatch and investment.

26. Development of intensive regional trade could be boosted by pooling arrangements including transit (i.e. wheeling) agreements. Where pooling arrangements are set in place, appropriate management structures are required and voting rules should ensure high degree of consensus on the operation of the pool.

27. Regarding international coordination between the different dispatching centers of the transmission companies, the experience accumulated within regional pools, and in particular the "loose" pools, such as in the US, Argentina or Norway, could provide valuable information.

ESMAP is greatly indebted to the management of each of the interconnected systems and/or power pools visited, for their time, effort and valuable information. It is hoped that the insights gained from the case studies can serve electric utilities in developing countries in their new coordination arrangements.

Finally, ESMAP acknowledges the financial support of the ODA which not only contributed the funds for this ESMAP study but also was instrumental in the selection of the consultant.

Note: **The present study is a follow-up of the report:**

"Development of Regional Electric Power Networks"

published in the same series in October 1994.

Impact of Power Sector Reforms on International Electricity Trade

Main Report

"Lessons Learnt"

- and

"Recommendations"

TABLE OF CONTENTS

1. Introduction and Conclusions

1.1 Introduction

During 1994, London Economics (LE) undertook a study of regional electricity trade arrangements. This covered NORDEL, trade between the regional electricity boards in India, South East Asia, Southern Africa, and trade within a number of electricity pools in the USA. The report on "Development of Regional Electric Power Networks" in June 1994 summarises the findings of this study, and these were presented at a seminar to the World Bank in Washington.

The World Bank has been actively promoting a reform agenda in the power sector. The objectives of reform vary by country, but typically include improvements to the efficiency of the power sector, and an increase in its ability to fund expansion without recourse to the government budget. The contents of reform packages also vary by country, but often include a mix of:

- unbundling, with vertical separation between generation, transmission and distribution, and horizontal separation between different generation units and distribution zones;
- an increased role for the private sector, often including private finance of new investment, privatization of some assets, or letting of long term concessions; and
- increased use of competition to set generation prices where possible, and introduction of independent and transparent regulation where competition is not possible.

It was clear from the first study that power sector reform can affect electricity trade, but further work was required to identify exactly what the impacts have been under different reforms. In 1995, the World Bank appointed LE to carry out a study of the impact of power sector reform on international electricity trade. The major aim of the project is to "identify the strategic, institutional, regulatory, pricing and contractual issues which need to be addressed for the enhancement of international electricity trade".

The impact of power sector reform on electricity trade can be assessed through looking at the experience of countries which have been through a thorough reform. These are still relatively few, and all have different characteristics. Norway has introduced an open pool, and Sweden has recently followed suit. This provides an interesting example of structural change, without any change in ownership. It can therefore help to separate which impacts on electricity trade are due to the structure of the market, and which to the new incentives which come about with privatization.

England and Wales has also introduced a pool, and accompanied this with wholesale privatization. The English pool has a number of external members, based in Scotland and France. The basis of trade pricing was fundamentally changed when the pool was introduced.

Latin America has also pursued a reform agenda. In Chile, Argentina, Peru and Bolivia this has included privatization. Chile and Argentina have also introduced electricity pools. The Latin American experience is of interest, since per capita incomes and electricity coverage are closer to those of the Bank's clients. The volume of regional trade is however relatively slight at present.

A number of other countries are presently pursuing a reform agenda. These include the USA, which is introducing a pool in California; Australia and New Zealand; and South Africa. Reforms in the USA and South Africa are at too early a stage to assess their impact on trade. Trade within a number of existing pools in the USA were covered in the earlier report. Australia and New Zealand have no potential for cross-border trade (although there is potential for trade between States) and so have not been covered here.

As a result, the study undertaken by LE covers three case studies where reform has been implemented. These are:

- Norway and Sweden;
- England and Wales and Scotland; and
- Latin America (principally Chile, Argentina and Uruguay).

In addition, a considerable volume of trade has been undertaken within Europe under the framework of the UCPTE. Much of this has been between traditional, vertically integrated and publicly owned utilities. As a further case study, we have examined trade within the UCPTE as an example of the form and volume of trade <u>without</u> power sector reform.

Volume I examines five aspects of power sector reform, and their impact on trade. These are industrial restructuring, the pricing of bulk power, shift from private to public ownership, transmission pricing and regulation. In each case we set out the possible reform agenda, summarise what has been done in our case studies, and describe the impact on trade.

Each section sets out our broad conclusions on the lessons for developing countries. As our case studies are predominantly developed countries, we have indicated where we think different conclusions might be drawn for developing countries.

Volume 2 contains the case studies.

1.2 Main conclusions

The main conclusions from this study fall into six categories:

1.2.1 Industry structure

- Vertical separation, and particularly the unbundling of transmission, is a very important prerequisite for efficient trade. There are several ways of achieving vertical separation, and unbundling transmission need not mean totally dismantling vertically integrated companies.
- Without horizontal separation (particularly in production) there may be inadequate competition, though trade itself can help increase the level of competition in generation markets.
- Without unbundling, trade can be distorted by the market power of producers and transmission entities. Third party access regimes are needed to give access to consumers.

1.2.2 Bulk supply pricing

- Marginal cost based pools provide vital information on system marginal costs that is necessary for trade to take place on an informed basis. However they are only feasible when systems reach a certain minimum size.
- The transition from traditional to pooling systems raises problems, notably that previous pricing regimes for international trade tend to break down, that trading partners may gain economic rents with unilateral liberalisation, and that there may be an adverse effect on either producers (if power is imported) or consumers (where power is exported).

1.2.3 Privatisation

- It appears that setting an appropriate market structure, rather than changing to private ownership, is the key to successfully increasing electricity trade.
- The worst performing entities are those that have most to gain from privatisation.

1.2.4 Transmission pricing

- Efficient transmission prices are important for optimal dispatch and investment decisions, and thus for efficient trade.
- Transmission prices that are bundled into the overall price of electricity delivered by a vertically integrated company often give completely wrong signals.

- Inconsistency between the transmission pricing systems of trading partners can be a barrier to trade.

1.2.5 Regulation

- Trade tends to be most favoured by competitive rather than regulated generation systems.
- There is an important residual role for government, which needs to be transparent.
- A key role of this kind is to regulate access to transmission systems.

1.2.6 Other

- It takes a considerable period of time to implement a restructuring programme in the electricity sector and to develop market trade on that basis. For instance Sweden, a highly sophisticated country, has taken five years to follow Norway in establishing a competitive market.
- It is important to establish adequate dispute resolution and arbitration procedures in advance of trade.
- There is considerable interaction between gas and electricity trade in some of the regions we have examined, including Latin America and Europe. In both, it is usually preferable to transmit gas and produce electricity locally. Similar issues will arise in developing countries, especially in Asia. But the economics of transmission are fundamentally different where energy flows are relatively small, perhaps in Africa, and electricity trade may be more economic than trade in gas.

2. Industry Structure

2.1 Introduction

Power sector reforms around the world have often included changes in industry structure. Vertically integrated industries have been unbundled, with commercial relations introduced between generation, transmission and distribution. There has also been horizontal separation, with the creation of multiple generation and multiple distribution companies.

Changes in industry structure can be accompanied by changes in ownership. However, the two can be kept distinct. Pacific Power for instance introduced vertical separation and competition in generation without ownership change. ESKOM in South Africa has introduced on a pilot basis, a competitive wholesale market, again without a shift from its co-operative to private ownership.

Changes in industry structure could affect trade in a number of ways:

- vertically integrated utilities may face a conflict of interest in dispatch. Being dispatched may increase their generators' profits, for example because they have a contract where energy charges exceed operating costs. In addition, the utility may have non-commercial objectives that lead it to favour its own generation. For that reason Independent Power Producers (IPPs) selling to vertically integrated utilities have often faced problems in being adequately dispatched. Vertical separation should remove this conflict of incentives. This will favour the use of imported electricity where this is least cost;
- vertical separation requires the introduction of commercial relations between sellers and buyers of bulk power. In most developing countries this has taken the form of long term contracts. It may also take the form of competitive wholesale markets. Regardless of its structure, the higher degree of transparency in bulk power pricing should again promote trade where economic; and
- horizontal separation also creates the potential for competition. This may be through a wholesale competitive generation market, or through competition for sale to final consumers. Both require equal access to the transmission network, and so are dependent on vertical separation.

All of our reforming case studies had introduced changes in industry structure. This section briefly describes what they were, and where relevant the impact on trade.

2.2 England and Wales

In England and Wales, the existing generation was split between two large non-nuclear companies and a (publicly-owned) nuclear company. Subsequently there have been a number of new entrants into generation, and divestments by one of the existing large generators are underway. However, the two largest generators still dominate the generation market.

Distribution was assigned to twelve regional electricity companies. These held captive or franchise markets, but with competition in final supply being progressively introduced. Transmission remained a regulated monopoly under National Grid Company, a private company.

England has interconnections with Scotland and France. Within Scotland, two vertically integrated utilities were retained, each with a transmission business in their respective areas. The interconnections with Scotland are owned by Scottish Power. Scottish Hydro has access rights to the interconnector. In addition, any other generator seeking to export from Scotland to England has to be offered a price for access to the interconnector.

The lack of open access to the Scottish interconnector has not historically caused problems. Substantial excess capacity in Scotland has reduced the case for entry by new generators. However, there is one exception to this. The Non-Fossil Fuel Order in England provides subsidies to specified volumes of power generated from non-fossil fuel sources. Scotland may provide relatively low cost sites for such investments, for example wind farms. However, potential investors have been concerned that their investments will be rendered non-economic due to high charges for the interconnection to England.

2.3 Latin America

The most fundamental reforms to industry structure have been in Chile and Argentina. Prior to reform Chile's power sector was very largely in public ownership. Revenue regulation was on a cost-plus basis. Final prices were set through different political pressures, with significant cross-subsidies.

Chile's reforms were introduced in 1982 through the Law of Electrical Services. Following the reforms, there are four principal generators, of which one is still Government owned; private transmission, of which the largest part is owned by ENDESA, the largest generator; and a number of distribution companies, some of which also own some transmission. The limited scope for competition in generation has fundamentally influenced the design of the wholesale electricity market, discussed below. In addition, there has been concern about possible conflicts of interest due to ownership of the largest part of transmission by the dominant generator.

Argentina's power sector was in crisis in the late 1980s. Plant availability factors were as low as 10%, quality and reliability of supply were low, and prices were too high. The government decided on a major restructuring of the electricity supply industry (ESI) and change of ownership. It chose to build on the Chilean model, with the vertical and horizontal unbundling of the industry and the introduction of a wholesale electricity market (pool). However, learning from Chile's experience, the government decided to make the reforms through a very general electricity law. This would facilitate making the later changes to the ESI which would be required as the reformed industry evolved.

Argentina's pool was established in 1991, with the plants still in public ownership. The wholesale market consists of two sub-markets, a spot market and a term market. The spot market accounts for about 35% of energy and the term or contract market for 65%. The latter market comprises generators and distributors with different length contracts. The distribution companies were privatised with eight year contracts, but new contracts are typically for one or two years.

Transmission was given to a number of companies. At a federal level, one company (TRANSENER) is responsible for the inter-regional HV transmission network. There are five regional transmission companies, responsible for the lower voltage networks. TRANSENER is only responsible for the operations and maintenance of the existing HV system. It is prohibited from investing in the new HV lines, which is to be done by private sector "beneficiaries", who may be producers, transmission companies or consumers.

The pool, the settlement system and contractual agreements with Uruguay, are administered by CAMMESA which has mixed ownership. The government holds 15% of the shares, the remainder being held by generators, distributors, transmission companies and large consumers, and the Secretary of Energy is also the Secretary of CAMMESA. The government has the right of veto, although it has only used this once.

2.4 Norway and Sweden

Norway's reforms also introduced changes to industry structure, although without the change in ownership that accompanied the UK reforms. Vertical separation was achieved through separating out the high voltage transmission grid, now owned by Statnett, from the largest generating company, Statkraft. There are a large number of small vertically integrated municipal utilities. They have been obliged to introduce separate accounting between their generation, transmission and distribution functions. Their transmission is also subject to regulation.

Norway already had quite a high degree of horizontal separation. The dominant generator, Statkraft, is publicly owned and has a little over 30% of capacity. This was not changed. There is a very large number of distribution utilities, around 200, and some pressure to reduce this number because of the difficulties of

effective regulation. The reforms also mean that there are a number of different kinds of players in Norway's markets, particularly:

- power producers;
- power distributors (normally small municipally owned utilities);
- vertically integrated companies;
- a HV grid company;
- brokers (who cannot hold an unbalanced portfolio of contracts) and traders (who can, and who from 15th January 1996 have been able to supply customers directly); and
- consumers, particularly large industrial users.

One objective of the reforms in Norway was to reduce the over-construction of capacity by (partially) vertically-integrated municipal utilities. There was no formal requirement for vertical separation, but the introduction of separate accounts made the costs of bulk generation for such utilities more explicit.

These vertically integrated utilities have now started to use the pool price - rather than some form of internal transfer price - as the basis of their bulk supply pricing. This is reflected in the convergence of retail prices following the reforms. Accounting separation appears to have played a role in making vertically integrated utilities more effective purchasers of bulk electricity. This should assist trade, where it is economic.

Up to this year, Sweden had a set of regional monopolies (area concessions) in both production and distribution. Major producers operated a system of production optimisation, buying power from the lowest-cost producer and splitting the difference between purchase and selling prices. Long-run contracts for the largest generators' use of the HV grid effectively limited the transmission access of other producers and led to vertical integration.

With the reform, this situation will end and the networks will be opened up to competing sales. The new electricity law, which came into effect on 1st January 1996, is the most important element of the reform, separating production from the networks. The reform will legally separate production and distribution from transmission and create full regulated third party access (TPA), under which the grid owner has to give access on reasonable terms unless he can prove that it would not be physically possible. The production and sale of electricity are open to competition (there will not be central planning of capacity expansion, rather the regulator will operate an authorisation system like that proposed by the EU), while special permission is needed to construct or operate HV lines.

Svenska Kraftnat owns all the 220 kV and 400 kV lines and most of the interconnections with other countries. This is becoming increasingly important with market liberalisation. In principle it is obliged to provide transmission to all parties. Kraftnat is responsible for balancing production and consumption both nationally and regionally, and for the market in regulating power. It is also

responsible for maintaining reliability by for instance setting standards for production plants and networks connected to the grid.

Production and sales will be under the normal competition authorities, while the networks will be regulated by a special network authority, NUTEK. To avoid cross subsidies, special requirements are imposed that tariffs should reflect the costs unequivocally connected with network operations in the relevant concession area. Network concessions relating to international links are subject to government approval, and all long term import and export contracts have to be reported.

The reform has been driven by the UK and Norwegian examples, and the need to keep power prices as low as possible - already they are among the lowest in Europe, reflecting Sweden's industrial development strategy.

From the point of view of the study, the most interesting element of the reforms is the attempt to create a joint marketplace with Norway. A particular issue for the design of ESI reform in Sweden has been the market power of Vattenfall, which controls around half of total generation capacity and about 15% of distribution. The state as Vattenfall's owner does not want to have it split up, partly to ensure that it remains comparable in size and negotiating power to potential customers and competitors abroad, such as RWE (Germany) and EDF (France). Foreign investment in Sydkraft, the second largest company, has led to worries about loss of national control.

The market power of Vattenfall would however probably distort prices in a pool established in Sweden alone, and this was one of the major considerations in choosing a joint pool with Norway, in which Vattenfall's potential market power would be greatly reduced.

2.5 UCPTE

The UCPTE is the Union for the Co-ordination of Production and Transmission of Electricity, and is an international electricity industry association whose members are chosen from representatives of the generation and distribution companies in its member countries. It was founded in 1951, and its current member countries are: Belgium, Germany, Spain, France, Greece, Italy, Slovenia, Croatia, Bosnia-Herzegovina, other regions of former Yugoslavia, Luxembourg, the Netherlands, Austria, Portugal and Switzerland. Since 18 October 1995 the systems of Poland, Hungary, the Czech Republic and Slovakia have been synchronised with UCPTE.

Only in the Netherlands, Spain and Portugal, of the UCPTE countries, is the ESI to any degree liberalised or market based. Vertical integration remains common, and France and Italy provide instances of nearly-complete vertically-integrated monopolies.

The volume of trade within UCPTE and between UCPTE and third countries is very large. During 1994 imports were 8.8% of total UCPTE production, while exports were 9.5% of total production. Exchanges of electricity have grown rapidly, and since 1975 total exchanges as a share of consumption have increased from 6% to over 10%.

The UCPTE experience raises the question whether it is possible that reform is in fact irrelevant to international trade, and whether trade benefits could be realised without the politically difficult upheaval associated with reform. In practice, as discussed below, there is strong evidence that UPCTE trade has been sub-optimal. Inefficient bulk electricity pricing and lack of, or poorly structured, transmission pricing means that the outcome is a level of trade substantially below what could be achieved with more open markets.

2.6 Conclusions

Vertical separation introduces greater transparency into system operations. Horizontal separation enables clear competition between generators. Both favour trade where it is economic.

Vertical separation can be partially achieved through accounting separation within an integrated utility. In Norway this has led to better bulk power purchasing, as municipal producer/distributors evaluate their internal transactions against trade opportunities. This may be dependent on development of a bulk power market, and on strong management.

Lack of open access to transmission networks has hindered trade. Industry restructuring should avoid leaving transmission with a major generator.

Creating effective competition between generators is difficult where one or a few hold significant market power. Trade, and where possible a joint marketplace across borders, can reduce the power of a large generator while leaving economies of scale untouched.

3. Bulk Supply Pricing

Vertically integrated utilities face a set of input prices - for fuel, labour, materials etc. - and earn revenue from electricity sales. The distribution of revenues within the organization may be undertaken through a financial department, based on management information systems. In many cases, internal transfer prices do not exist, and there is no price information on the efficiency of different generators.

Power sector reform and vertical separation require the introduction of commercial relations within the sector. This may take the form of accounting separation, with formal transfer prices within a vertically integrated company. This was done for example in integrated Norwegian utilities, and in the two Scottish utilities.

With full separation, fully commercial relations are needed for bulk power. These may take the form of a long term contract. In Northern Ireland for example all generators were placed on long term contracts prior to privatization. These followed the standard form for IPP contracts, with separate payments for capacity on the basis of availability and energy on the basis of kWh generated.

The alternative is the introduction of a wholesale electricity market or pool. Generators are then paid the marginal cost of energy at each period, set by the highest cost generation plant selected, and known as the system marginal price. Generator cost may be set by competitive bids, or through auditing the production costs of different plants. Generators are also paid the marginal cost of capacity. This is set in a number of different ways, but is essentially designed to pay generators according to the probability of load being lost, and the value of load when it is lost.

Both contracts and pools provide much clearer signals on the costs of generation to both purchasers and competing suppliers. They should favour trade where it is economic. Our case study countries had all introduced pools. Their structure and impact on trade are described below.

3.1 Norway

Historically, trade between the countries of the NORDEL region[1] was operated under a loose pooling arrangement with no central dispatch. This was dominated by day-to-day exchanges, although with some long term contracts. Exchanges were based on the split savings principle, with exports and importers benefiting equally from the difference between the system marginal price in the two systems.

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[1] Norway, Sweden, Denmark and Finland. Iceland is also a member, but has no trade with the others.

Trade operated on a large scale and with a considerable degree of success. For instance in 1990, Sweden imported 12.3 TWh of electricity from Norway, or about 9% of its total electricity use in that year, and exported an even larger amount to the other Nordel countries. However, substantial price differentials remained. In 1989, for instance, industrial power prices were lowest in Norway (with its large hydro resources)and progressively higher in Sweden, Finland and Denmark.

Table 1 : Average price of firm power to industry (Norwegian Kronor per kWh), 1989

Norway	Sweden	Finland	Denmark
0.11	0.24	0.35	0.42

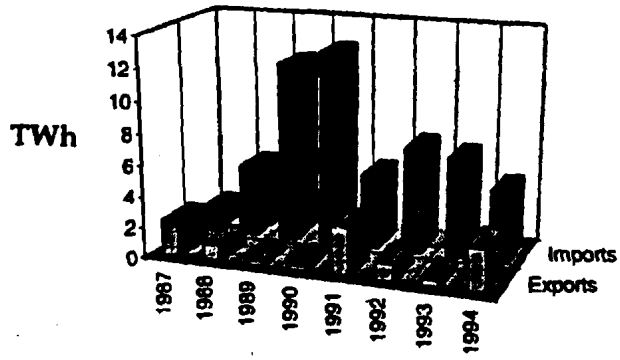
On the introduction of Norway's reforms in 1991[2], Sweden initially refused to accept that Norway's Pool price fairly represented Norway's system marginal costs, and the mid-price arrangement governing Nordel trade between the two countries broke down. Swedish and Danish buyers and sellers subsequently started to bid in the Norwegian Pool.

This was accompanied by a rapid decrease in Norway's power exports, and a question raised at the time was whether this decrease reflected strains on the international trading arrangements as a result of Norway's unilateral reform. The Figure 1 below illustrates that the reduction marked the exceptionally high level of trade in 1989 and 1990, due as much to high water availability in both countries as to a fall from the long term trend provoked by restructuring.

[2] These reforms centred on unbundling the transmission company (Statkraft) from the main generator, guaranteeing third party access to the network, and opening up the longstanding producers power pool to bids from consumers. They are explained more fully in the Norway case study in Volume 2.

Figure 1:

Swedish Exports/Imports with Norway



The longer term impact was to make exports more profitable and increase Norwegian producers' interest in exporting power. This benefits Norwegian producers and Swedish consumers at the cost of Norwegian consumers and Swedish producers. In 1992 the Norwegian Government stipulated a limit on power exports of 5 TWh/yr under contracts of from 6 months to 5 years duration, in order to avoid undue increases in Norway's domestic prices.

Long term contracts increased their share of trade, and currently account for 70-80% of total Norway/Sweden trade, and for 1/2 to 2/3 of interconnector capacity. They are given priority over spot trades, and have to pay a priority fee for this privilege. Kraftnat and Statnett decided what contracts to accept; the restrictions are mainly on the Norwegian side where exporters need licenses from the authorities. Further bilateral contracts are not now being accepted, in order to make room for more spot transactions.

Norway is thus moving its international trade from a pattern of short term transactions based on surplus capacity, combined with relatively restrictive long-term contracts, to one based on spot transactions between generators and customers, regardless of their nationality.

The joint marketplace

One of the further features of the reform that is of most interest for the current study is the creation of a joint marketplace in electricity for both Sweden and Norway. Even before the reform in Sweden, about 10 of the actors in the existing Norwegian marketplace were Swedish, and their number is expected to increase.

A joint pool was formed at the start of 1996, and the Swedish grid operator (Svenska Kraftnat) now owns half of the pool organisation (formerly the Norwegian company Statnett Marked). The joint pool company is based in Oslo but will have a Stockholm office, which will initially be just an information centre but may later be able to be used for bids.

The pool is voluntary, not compulsory as in the UK, and there is no central dispatch (for the two countries). In preparation for the joint pool, Kraftnat and Statnett have increased transmission capacity and worked to harmonise tariffs, system responsibilities and regulating markets in the two countries.

It is premature to assess the impact. However, in the first few weeks of 1996, unusually mild weather in both Norway and Sweden has led to a situation in which transmission bottlenecks within Norway are occurring, and a uniform price has emerged between northern Norway and Sweden, while prices in southern Norway are lower.

3.2 England and Wales

Following privatization, a wholesale pool was developed. Generators bid a day ahead, on a half-hourly basis. The lowest bids are accepted, on the basis of unconstrained dispatch. All generators are paid the system marginal price, that is the bid of the last generator selected. Generators, including those not selected, also receive a capacity payment explicitly related to the calculated probability of lost load and an indexed measure of the value of lost load.

England has interconnections with Scotland and France. Trading arrangements before privatisation centred on export and import offers. Export offers were costed at the marginal cost of generating and transmitting energy to the border after satisfying internal demand. Similarly, import offers were based on the potential cost saving of not running domestic generating sets less the cost of transmission losses from the border. The trading price would then be set mid way between the export and import offers.

Following privatization, the two Scottish utilities and Electricite de France were external members of the Pool. The Scottish utilities have long term contracts governing use of the interconnection, and bid available generating capacity into the Pool. If successful, energy is centrally despatched by the Pooling authority. The arrangements do not amount to a joint optimisation of the English and Scottish systems as the vertically integrated Scottish utilities continue to despatch energy in their franchise areas.[3]

The share of imports from Scotland and France in the English system has increased from 3.2% to over 8%. The interconnection with France had for some time been heavily used. The increase was principally due to greater use of the interconnection with Scotland, and expansion of its capacity.

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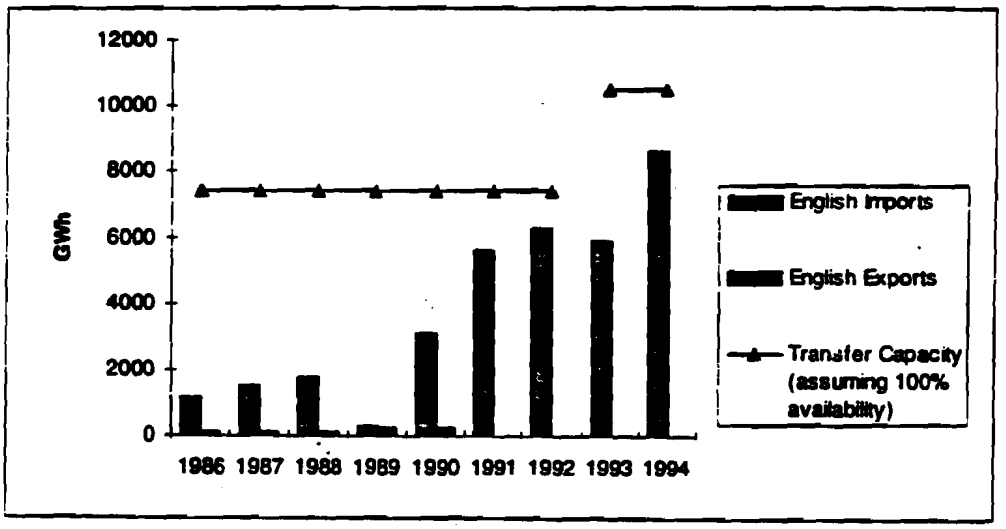
[3] Scottish despatch is backed by a licence obligation to purchase power at least cost, and the two Scottish utilities have set up a bilateral trading code to ensure merit order despatch within Scotland. This trading code does not, however, take English plant into account.

In the early 1980s, Scottish exports of electricity varied between 1000 GWh and 2000 GWh per year. Following privatisation, the capacity of the interconnection was upgraded in 1993 from 850 MW to 1200 MW. Current plans envisage further expansion of capacity to 2200 MW, though further reinforcement of the English transmission will be required to utilise this capacity. Scottish exports increased dramatically, rising from 1161 GWh in 1986 to 8606 GWh in 1994. Figure 2 illustrates the pattern of trade.

Figure 2: Electricity Trade Across the England-Scotland Interconnection



The causes of this dramatic increase in trade are discussed in detail in the case study. The two principal explanations are:

- following privatization, the Scottish utilities had a low degree of flexibility. They were obliged to take nuclear power and gas under take or pay contracts. They also had obligations to take coal (although this could be stored) and had a significant share of hydro. They faced the risk of an obligation to take energy in excess of their sales. The trade could be contract driven, since for a large part of their energy the marginal cost was effectively zero (since they were obliged to pay); and

- the pricing system gave much clearer signals on the value of energy and capacity. Many commentators have argued that prior to privatisation, the Central Electricity Generating Board which was responsible for generation, despatch and trade, systematically understated import offers, preferring to run its own generators rather than import power. After privatization, the cost advantages to the marginal plant in Scotland (typically a relatively efficient large coal plant, which also enjoyed some pricing advantages) became clearer and drove exports.

3.3 Latin America

In Argentina, the pool was established in 1991, with the plants still in public ownership. The wholesale market consists of two sub-markets, a spot market and a term market. The spot market accounts for about 35% of energy and the term market for 65%. The latter market comprises generators and distributors with different length contracts. The distribution companies were privatised with eight year contracts, but new contracts are typically for one or two years.

The spot market has been important in realising the benefits from the reform of the electricity supply industry[4]. Both generators and distributors are active in the spot market. Distributors have strong incentives to sell part of their long term contracts when the value of lost load is high (the VLL varies from US $120 to US $1500/MWh) and the contracts exceed their requirements. The thermal generators declare their variable costs to CAMMESA every six months[5]. Until March 1995 CAMMESA fixed the opportunity cost of water, but this is now done by the hydro stations themselves[6].

CAMMESA makes the price calculations and prepares the dispatch schedule weekly in advance. The dispatch schedule is for the thermal, hydro and so-called fault units. The latter units relate to supply interruptions when available generation capacity would be insufficient to meet forecast demand[7].

In the constraint periods, all generators dispatched receive the fault unit price, adjusted for losses at the appropriate node on the system. Since in the absence of supply interruptions the normal spot price (excluding the fault unit price) is around $22-25/MWh, this provides a strong incentive for units to be available.

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4 For example, while the thermal plants sell to EDENOR at $39.53/MWh under their vesting contracts, in late 1995 the average market price was around $25/Mwh. The vesting contracts have reduced the fall in prices to final consumers, although average prices to consumers have fallen by about 12% in real terms.

5 These prices are not allowed to exceed by more than 15% the reference price for each type of fuel (gas, gasoil, fuel oil, etc.) which is calculated by CAMMESA. To date most thermal plants have declared prices below the reference prices.

6 Plants with large reservoirs do this every six months, while those will small reservoirs do it monthly.

7 The fault unit price depends on the magnitude of the supply shortage, as follows:

Supply Shortage	*US$/MWh*
0 - 1%	120
1 - 5%	170
5 - 10%	240
Above 10%	1500

CAMMESA is also responsible for the settlements system. Generators receive payments for energy, capacity and ancillary services. Energy payments are calculated on the basis of the energy generated and hourly spot price at each node (allowing for losses). Three different capacity payments are made.

- dispatch. All generators which are dispatched received $10/MW in peak hours of their maximum generating capacity allowing for transmission constraints (e.g. installed capacity 200 MW, but limited to 100 MW by transmission constraint. Payment of 100 x $10/hr, even if less than 100 MW is called for dispatch);
- base power. This is paid to thermal plants for each hour at which they are available ($10/MW) in specified hydrological conditions; and
- standby power. Each generator offers a price to provide standby power. CAMMESA ranks the offered prices, and determines the capacity required to provide the standby power. All selected plants receive the price bid by the marginally selected plant.

Largely because of it geographical position, Uruguay has been and will continue to be of key importance for electricity trade in the region. To date this trade has been focused on Argentina, both through the jointly owned Salto Grande plant and a 1978/9 agreement on electricity trade. Under this agreement trade has been of two types. First for "substitution" energy, which is based on differences in the SRMC in the two countries, with the cost savings being shared equally between the two parties. In the past the variation in short run costs has been between US $0/MWh in Uruguay and US $40 MWh in Argentina. Second, trade in emergency energy, with capacity and energy charges.

The 1978/9 agreement has been important, and in some years (e.g. 1992) Uruguay exported nearly 50% of the energy generated. However, various problems have arisen following the reform of Argentina's ESI which need to be resolved if trade is to continue to be important and to grow. These include issues related to Uruguay selling into Argentina's pool, to possible distortions arising from TRANSENER's transmission pricing system, and to ways in which new transmission investments would need to be financed in Argentina.

The pricing issue relates to bidding into Argentina's pool. Trade is still occurring on the basis of the 1978/9 agreement. However, UTE would like a new agreement under which it would bid into Argentina's pool. This would tend to raise prices in Argentina and lower costs in Uruguay, so while Uruguay would benefit from receiving the pool price, consumers in Argentina would lose. A similar issue has arisen in Southern Africa with the development of the SAPP raising the possibility of substantial external purchases from ESKOM's pool that would raise pool prices. It has also been identified as an issue for future sales from the Bonneville hydro project into California's proposed pool.

Both Chile and Argentina have competitive power markets, and there is pressure on companies to achieve cost reductions, to which energy trade could contribute. However there are no significant electrical interconnections between the two countries at present, and little likelihood that they will develop in the near future. The gains from trade are more likely to be realised through trade in gas, whose economics are more favourable than those of trade in electricity.

3.4 UCPTE

The UCPTE is, in effect, a club which lays down the technical specifications governing electricity trade between its members and arbitrates in disputes between them. The individual members collaborate voluntarily and each remains solely responsible for supplying its own customers. There is no pool, and trade takes the form of bilateral exchanges under contractual relationships, mainly under long term contracts for firm energy. A spot market for short-term exchanges of power also operates, but this too is based on agreements between utilities rather than a pool.

The short-term power market with unsecured energy supplies (the spot market) is the result of the implicit comparison of marginal costs of generation. Information on availability, kWh prices and delivery conditions is made available through an UCPTE-organised e-mail system to all interconnected partners to assist grid control centres in arranging transactions. In addition to short term exchanges there are a large number of bilateral contracts[8] between UCPTE members. The case study on the UCPTE describes a number of these in more detail.

How far has this mix of short term trade and long term contracts succeeded in reducing price differentials in the region? Industrial electricity prices in the main UCPTE countries provide an indicator of the level of bulk supply prices. Price differentials are to some extent consistent with the trade pattern. Power prices are relatively low in France, the main exporting country, and relatively high in Italy, which is a large importer and Spain where imports are increasing.

[8] And a trilateral contract involving France, Spain and Portugal, see Volume 2

Table 2 : Industrial electricity prices in selected UCPTE countries, January 1994 (ECU/00 kWh, excluding tax)

	10 GWh/yr	70 GWh/yr
Belgium	6.9	4.2
France	6.5	4.6
Germany	10.0	7.2
Italy	8.4	5.0
Netherlands	6.2	4.3
Portugal	8.5	6.0
Spain	7.2	5.8

Source: Eurostat "Electricity Prices 1990-94", Brussels 1994, page 190

However, price differences clearly persist, despite the extent of the electricity trade that is occurring, and are above the level that would be justified by transmission costs. It is therefore appears that trade is not exhausting all the opportunities that would currently be economic.

The European Commission has been pressing for liberalisation in the EU power market, and in particular for the introduction of third party access (TPA), initially on a regulated basis but following debate with the utilities of member states on a negotiated basis. An alternative more centralised proposal, the Single Buyer Model, is also being considered under which national utilities would retain control over all power deliveries though consumers would be free to enter into transactions with other suppliers.

London Economics has examined the impact of enforcing third party access to transmission networks in Europe. In a recent study for the EU[9], we estimated the likely impact of the TPA proposals on the level of intra-European electricity trade, over the period up to the year 2020. Taking the EU as a whole (rather than the UCPTE), current electricity imports are approximately 6% of total demand. In the absence of reforms to increase competition, this would be expected to decline gradually, principally because the increasingly widespread adoption of the latest gas-fired generation technologies in many countries leads to gradual cost convergence.

[9] Completion of the Internal Energy Market, Interim Report to the European Commission, December 1995

With the full competition that would accompany TPA, by contrast, it is predicted that the share of imports would rise fairly rapidly to about 10% of total demand within the next decade. Thereafter the import share would begin to decline again as costs are harmonised across countries, reaching about its starting level in 2020 but remaining above the level that would prevail in the absence of liberalisation. Much of the increase would reflect greater exports from France to the Benelux and Iberian countries.

3.5 Conclusions

Almost all trade in developing countries is based on exchange at the border between vertically integrated utilities. Trade contracts tend to be based on incurred and avoided costs. In the Southern African Power Pool, this has been formalised, and in other cases it forms the basis of negotiated prices.

Marginal cost-based pools provide far more information on system marginal price at different periods, and provide a mechanism for selecting the cheapest generators. There is strong evidence that this increases trade. However, for many developing countries the small size of the generation sector, or its domination by a few large generators, will prohibit competitive pooling.

Where pools are feasible, three problems may still arise with respect to trade:

- *when they are introduced for generators in one country, the organisational basis of former trading regimes may break down, and trade may decline unless it is explicitly replaced with compatible arrangements such as "external" pool membership for generators partner countries;*
- *if external generators are low cost, allowing them to join the pool may increase their revenues. Countries may prefer to use their market power to exclude external generators, and seek to negotiate contracts which share the economic rent; and*
- *if domestic generators are low cost, cross-border pooling will increase domestic prices, and may be politically unacceptable.*

4. Privatization

4.1 Introduction

Power sector reform around the world has often started with private investment in new generation. In some cases, existing assets have been privatized either under asset sale or long term concession.

Privatization can assist with financing through sale proceeds. It can also increase the efficiency of utilities through giving them a clear commercial mandate, increasing managerial autonomy and providing managers with strong incentives to increase profits. Since revenues are typically regulated, this provides strong incentives for cost reduction.

This process could be expected to increase trade for two reasons:

- where managers have strong incentives to minimise costs, they will seek out trade opportunities where these are economic; and
- governments often place strong emphasis on national self-sufficiency. It is noticeable for example that the strong interconnected systems of the former Soviet Union are trading less following the creation of separate countries, and in some cases investing uneconomically to replace trade. There is less reason why private companies with a commercial mandate should seek to avoid trade.

4.2 Case study experience

Our case studies present a wide diversity of experience. In Norway and Sweden, reforms were to industry and market structure without changes in ownership. In England and Wales, the power sector was entirely privatized, other than the nuclear power stations. Proposals to sell these are still under discussion. Latin America has seen a high degree of privatization.

The privatization in England and Wales followed on from a number of preparation steps to ensure success. In addition to the introduction of the pool, described above, these included:

- successive real tariff increases in the years running up to privatization, to increase the profitability of the companies;
- write down of assets, to avoid the need for further tariff shocks;
- vesting contracts, designed to secure generator revenues, and to protect the domestic coal-mining industry for a period of about five years; and

- investments (mostly after privatization) of around $100M in coal import facilities to allow imports and more effective negotiation with domestic suppliers.

Argentina's privatisation programme began in 1992, with the privatisation of two thermal plants, one of which was bought by ENDESA of Chile. In order to ensure that privatisation would be successful, these thermal plants were given eight year contracts (at what turned out to be high prices) with ENDENOR, the privatised distribution company in Buenos Aires. Subsequently the hydro plants were also privatised (Hidroelectrical El Chocón S.A., the first plant to be privatised, was also purchased by ENDESA).

Reform in Argentina has led to some very dramatic improvements in performance. One company reported an improvement in average plant availability from 10% in 1991 to 70% in mid-1995. Pool prices have been below forecast due to efficiency improvements.

Chile's privatization programme followed on from steps to increase sector efficiency. Prior to privatization the State owned 98% of generation, 100% of the transmission network and 80% of the distribution network.

The second-largest generator, Colbun, remains in State ownership, but all other generation has been sold. The central transmission system, accounting for 64% of consumption, was privatized along with ENDESA, a generating company. Distributors operate under long term concessions. The entire sector has been privatized, although the State retains some participation in a number of companies through a subsidiary, ODEPLAN.

It is difficult to separate out the impact of privatization from that of structural and market reform which was also pursued in both countries. However, both Chile and Argentina achieved striking improvements in sector efficiency. It seems probable that it would have been hard to achieve these with the embodied management culture. The development of gas interconnection, which has been much discussed, also appears to have been speeded by private sector involvement in the electricity industry.

UCPTE members have a mix of private and public sector participation in the power sector. The UCPTE has seen much less privatization in recent years. Austria has sold 49% of the transmission utility, Verbund, and of three regional utilities. Portugal has sold generation capacity. For most countries in the UCPTE, ownership has been stable.

4.3 Conclusions

In theory incentives for efficiency can be provided under public as well as private ownership. The gains achieved in Norway, with structural change but without privatization, suggest this is also true in practice.

Where inefficient management cultures and poor performance have become strongly embedded, it may prove difficult to improve efficiency through public sector reform. This may be true in many developing countries.

The preparation for privatization typically requires steps to protect domestic lobby groups, including the power and energy industries. In the short term this may hamper trade. The long term effect should be to increase trade where economic. In some cases this may be trade in primary energy for power generation, rather than trade in electricity.

5. Transmission pricing

Electricity trade decisions are often based on relatively small differences in generating costs. Transmission costs, therefore, can have a significant impact on trade. In most systems, transmission pricing is relatively unsophisticated. Few systems have developed pricing systems that give accurate locational messages to generators and consumers. In many cases, transmission charges are rolled into sales price for trades between vertically integrated utilities.

With the unbundling and restructuring of electricity supply industries, however, transmission pricing is beginning to attract greater attention. The principles for setting efficient transmission prices are now well described[10]. They would reflect the marginal costs of transmission made up of:

- congestion costs, that is the cost of any out-of-merit running arising from transmission constraints;
- marginal losses, which will be substantially higher than average losses; and
- a marginal capacity cost reflecting the probability of loss of load in the transmission network.

Generators are paid these costs (plus marginal generating costs) at their respective input node, while consumers are charged the same costs for their respective output nodes.

The efficiency gains from this structure of pricing arise from the price signals which are then given with respect to:

- power station dispatch in a merit order that takes into account not just marginal generation costs but also transmission losses;
- the location of new power stations based on prospective nodal payments as described above;
- investment in the development of the transmission network;
- the pattern of consumption; and
- investment in electricity consuming plant and equipment.

Transmission pricing is becoming an increasingly important issue as electricity industries are reformed. Amongst our case studies, there has been significant reform in the UK, Norway and Sweden, and in Argentina. The remainder of this section discusses transmission issues and trade in practice.

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[10] See for example London Economics report *Bulk Power Pricing in Competitive Markets*, May 1995, or Ignacio Perez-Arriaga *Pricing of Transmission Services* June 1992 Working Paper IIT-92-030.

5.1 Trade and transmission between Argentina and Uruguay

As noted above, Uruguay and Argentina have traded marginal energy both through the jointly owned Salto Grande plant and under a 1978/9 Agreement. The Agreement covers:

- short term trade based on cost differences and savings split equally between the two trading partners; and
- emergency trade based on capacity and energy charges.

For most of the period since 1978, this trade has been conducted between vertically integrated utilities, and transmission pricing has not been explicitly considered. However, reform and unbundling of the electricity industry in Argentina since 1991, has raised serious challenges for the further expansion of trade.

Argentina's reform programme introduced functional disaggregation and competitive generation and supply markets. Generators have been privatised as individual stations or in small groups, the transmission network has been brought together under one major company TRANSENER with open and non-discriminatory access offered to all, and a pooling system established. Section 2.3 discussed the pricing problems that have arisen.

Perhaps of greater concern is the issue of transmission pricing. The reform of the electricity industry is only beginning in Uruguay. Under the reform programme, the existing power utility will be broken up into three business units, generation, transmission and distribution, but remain in public ownership. Until the reform is implemented, Uruguay will not have a system of transmission pricing.

In Argentina, on the other hand, transmission pricing though sophisticated is highly complicated (involving for instance two fixed and one variable charge)[11]. Under the Argentinean regulatory framework, the price charged for the use of the transmission system recovers only operating and maintenance costs.

Expansion of the transmission network is also closely regulated. While TRANSENER may take the initiative, network expansion must be financed by beneficiaries in the private sector (the generating and transmission companies and large consumers), and 70% of the beneficiaries must agree and support the expansion. The capital costs of the expansion must be recovered over 15 years, after which transmission pricing must be lowered to reflect operating and maintenance costs. In practise, under these rules, it has been difficult to build sufficient consensus to expand the transmission network.

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[11] See London Economics report *Bulk Power Pricing in Competitive Markets*, May 1995.

Argentina and Uruguay intend to shortly sign an agreement to jointly operate and despatch their respective systems at the 500 kV level. As part of this project, conventions on how to value water, the calculation of the short run marginal cost of thermal plants and common technical standards will be agreed. This would amount to a radical strengthening of trade relations.

However, such an agreement cannot be implemented until:

- transmission pricing rules are set in Uruguay;
- the Argentinean regulatory framework is simplified to allow expansion of the network required for trade; and
- the two approaches to transmission pricing are standardised.

5.2 Norway and Sweden

Norway

Prior to the 1991 Energy Act, transmission prices were based on the distance between generating plant and the customer, and a transport element was included in the actual electricity price. In 1992 this was replaced by an area-based system, under which:

- both customers and generators have to pay for the use of the transmission network;
- network owners have a duty to calculate the price for the input and output of power; and
- paying the price established for a connection point gives access to the entire network and electricity market.

Statnett first calculates the Main Grid tariff. Regional networks then set their own tariffs including their costs of access to the Main Grid.

The transmission prices in this system are a simplified version of theoretically efficient nodal prices. Each tariff has both:

- a variable element, consisting of an energy fee and a capacity fee; and
- a fixed element, composed of connection and power fees.

The energy fee: This covers losses, based on typical power flows and system loading. It is defined for five tariff areas and three representative time periods, and for 3-4 representative input and output points in each area. It varies considerably over time and from one part of the country to another.

The capacity fee: When a transmission bottleneck is foreseen, the information is passed on to the market in the form of a map. Traders then have to balance their supply and demand by area - prices will be lower in surplus than in deficit areas. Buyers and sellers have to differentiate their bids, and the capacity fee is the

differential between the system price (calculated as it would have been for the whole country without constraints) and the area price.

The connection fee: This is intended to reflect costs related to Main Grid reliability and system operation. It is levied on the basis of total demand.

The power fee: This is a residual charge, not related to capacity, levied to recover the costs of the Main Grid, which in 1995 was about half of total grid revenue. It is levied on the basis of measured power exchange for each connection point.

Power trade with neighbouring countries are based on the transmission tariffs applicable in Norway, but adjustments have to be made to enable exchanges between the open system in Norway and the more closed systems in other countries.

Sweden

Before the reform, Sweden's transmission prices were based on transmission "channels", and there will be a major changes in Sweden's transmission tariff as it switches to a node-based system, where charges are made for use of system.

In 1995 there was a border tariff charge on either side of the border, representing about 10% of the transmission costs. Border tariffs will be abolished and trade will be on a fee for transit basis. The adoption of new transmission tariffs will mean that all customers and suppliers in both Norway and Sweden are able to trade without border tariffs.

The transmission tariff has 2 elements:

- the power fee (55% of revenue) expressed in Skr per megawatt per year; this is set as a residual to recover the full costs of transmission infrastructure; and
- the energy fee (45% of revenue) based on marginal losses.

If transmission bottlenecks occur, a tariff uplift will be implemented. All this is very similar in principle to the area tariffs in Norway. However, the Swedish tariff has a somewhat different design, in that the charge covering infrastructure costs is linked to the energy fee, rather than being a flat charge as in Norway. The result is that the Swedish system has much stronger locational incentives than the Norwegian one does. The Norwegian system is arguably closer to the theoretical ideal, but there is little experience in this area and the persistence of transmission bottlenecks within Norway suggests that there may be some merit in the Swedish approach.

Up to 1995, the border tariff between the two countries was the sum of the exit charge from one network and the entry charge to the other. This year, a harmonised nodal tariff has been introduced, encouraging border-free trade between the two countries.

5.3 Transmission pricing and access in the UCPTE

Transmission has not been vertically separated and is not separately priced in many EU countries. Exchanges are typically at the border, with any transmission costs and losses embedded in the border price for each utility.

Tripartite and wheeling contracts include transmission pricing. A detailed case by case study of specific contracts is necessary to identify the embedded transmission charges.

Our case study gives some examples. A particularly interesting case is the tripartite agreement between Electricite de France, REN of Portugal and REE of Spain. The contract arrangements are complex, but the underlying objective was a transfer of power from France to Portugal. REE did not receive a wheeling charge, but did receive power, to compensate it for transmission losses and implicit use of system charges.

Within Spain, the main supply area is in the Northwest, while the main demand is in the Northeast. Wheeling power for REN was therefore against Spain's internal power flows, and should have reduced rather than increased REE's costs.

Concern over the impact of transmission monopolies has led the EU to push hard for Third Party Access (TPA) and international transit. The present state of the debate is summarised in our case study.

5.4 Conclusions

Transmission pricing can in theory affect dispatch and investment decisions, and the allocative efficiency of electricity prices. Quantitative analysis confirms that these effects can be significant. They will often be greater in developing countries, given their relatively low loads and the need in some countries for long transmission links.

"Bundled" transmission prices can conceal very distortionary pricing. Vertical separation of transmission, and transparent and well formulated transmission pricing, will promote generation efficiency and trade where economic.

Inconsistent transmission pricing between countries can be a major obstacle to the development of trade.

6. Regulation

Power sector reform has promoted private sector participation for both financial and efficiency objectives. Where private investment is simply for generation, this can be regulated through a contract (typically with the existing utility) and a clear set of dispatch rules. If generation is in a competitive market however, regulation of transmission access is also required.

Power sector reform also needs to address regulation of the final tariff. This is clear where investors are required to take exposure to final tariffs, for example through the privatization of distribution. It may also be necessary to increase the profitability of the incumbent utility. If the utility is persistently loss-making, it will be unable to sign credible contracts with potential IPP investors. IPP investment will depend on sovereign guarantees, and so fail to remove power sector financing from the Government budget.

Two elements of regulation may be relevant to cross-border trade. These are the regulation of generation, and the regulation of transmission access.

6.1 Generation

Norway, England & Wales, Chile and Argentina rely on wholesale electricity markets to provide correct signals for new investment and operation, and to minimise costs. In Norway and England & Wales the wholesale market relies on bids from generators, and depends on competition to ensure that bids are reflective of marginal costs. As a result there is little or no direct regulation of generation. Chile and Argentina use declared costs, rather than bids, and an administrative procedure for valuing hydro output and the opportunity cost of water. Further details of these and other market structures for bulk power are given in London Economics' report, Bulk Electricity Pricing in Competitive Markets (March 1995).

Despite this generally low degree of regulation in bulk supply, several Governments have been concerned to ensure that the benefits of cheap generation and/or reliability are retained for domestic consumers rather than exported. In 1992, the Norwegian Government stipulated a limit on power exports of 5 TWh/year under contracts of from 6 months to 5 years duration, to avoid undue increases in domestic prices. According to NUTEK (Swedish Electricity Market 1995, p.15), the Swedish Government thinks that "opportunities should be available for placing certain restrictions on foreign trade ... if the reliability of supply should be threatened in the future".

Similar issues arose in the UK. In Scotland, the area served by Scottish Hydro had traditionally benefited from cheap hydropower. At privatization, a cross-subsidy between the generation and transmission businesses within Scottish Hydro was set in place. The purpose of this was to avoid Scottish Hydro exporting the economic rent.

Although the government's role in Argentina's energy sector was substantially reduced following the reform and restructuring of the electricity and gas industries, it continues to be important for international trade in energy. This occurs in a number of ways, including:

- the government must approve any proposed gas or electricity trade. Thus, under the electricity law the Secretary of Energy is responsible for approving proposed electricity imports and exports. He is advised by the regulator, who is responsible for assessing the effects of proposals on other players in Argentina's energy sector;
- it continues to engage into inter-governmental discussions aimed to increase energy trade; and
- proposed political/regulatory agreements must be approved by the Secretary of Energy.

6.2 Conclusion

Where competition in bulk generation can be made effective, the need for regulation is much reduced. Optimum price signals are provided for trade. Some developing countries will be unable to ensure competition due to the small size of the generation sector. They will need to retain regulation of bulk supply prices, most usually through contracts.

Governments are likely to retain a residual role in ensuring security of supply, and politically acceptable price impacts. These objectives should be made transparent and fully quantitative, to allow trade to proceed to the acceptable levels.

6.3 Transmission access

Lack of access has physically prevented trade in some of our case studies, and regulating to ensure access is a key issue everywhere. In Sweden for example, the pre-reform system of "area concessions" gave exclusive rights to the transmission links and prevented access for third parties. When, following the reforms in Norway, clients in Sweden wanted to import from Norway, they were often prevented from doing so by lack of transmission access. Similarly in Scotland, access to the interconnection with England is controlled by Scottish Power and interconnector capacity is entirely tied up by existing producers, leaving no room for independent power producers to enter.

Meanwhile, the EU has made third party access and international transit issues central to the debate on alternative models for the power sector. Starting from a proposal for an open access regime (mandatory or regulated TPA), the European Commission has been obliged to progressively water down its proposals by serious opposition from Member States with vertically integrated utilities. It is currently proposing a regime of limited or negotiated TPA, but still faces opposition from countries with strongly centralised systems which favour the so-called Single Buyer Model. The UCPTE case study in Volume 2 provides details of this debate.

6.4 Conclusion

Open access to transmission networks is a necessary condition for effective competition in the power sector. Adequate access to interconnectors is particularly important for trade.

Impact of Power Sector Reforms on International Electricity Trade

Case Studies

1. Scotland-England
2. Norway-Sweden
3. Western Europe (UCPTE)
4. South America

Case Study 1: Electricity Trade Across the Scotland-England Interconnection

Case Study 2: Norway - Sweden Case Study

Case Study 3: Electricity Trade in Europe

Case Study 4: Electricity Trade in South America

Regional Grid Networks 2

Case Study 1 : Electricity Trade Across the Scotland-England Interconnection

Electricity Trade Across the Scotland-England Interconnection

Table of Contents

Electricity Trade Across the Scotland-England Interconnection

1. Introduction

The electricity industry was nationalised by Parliament in 1947. The electricity supply industry in England and Wales comprised the Central Electricity Generating Board and 12 publicly owned distribution entities. The Scottish system comprised two integrated generation and distribution entities with a geographical monopoly - the South of Scotland Electricity Board (SSEB) and the North of Scotland Hydro Electric Board (NSHEB).

Through the post-war period, electricity demand increased strongly. The industry invested heavily to meet this demand and preserve system security. The growth of energy demand levelled off during the 1970s following the oil price shock. The over-capacity and inefficiency in the electricity industry became increasingly visible and criticised.

In part to meet these criticisms, and driven by political commitment to privatisation, the electricity industry was restructured in the late 1980s. The industry in England and Wales was unbundled and corporatised into two generators, 12 distribution companies and a national grid company in 1989. A pool was set up as a wholesale market for electricity, and the distribution companies were privatised in 1990. The two major generators, National Power and PowerGen, were privatised in 1994.

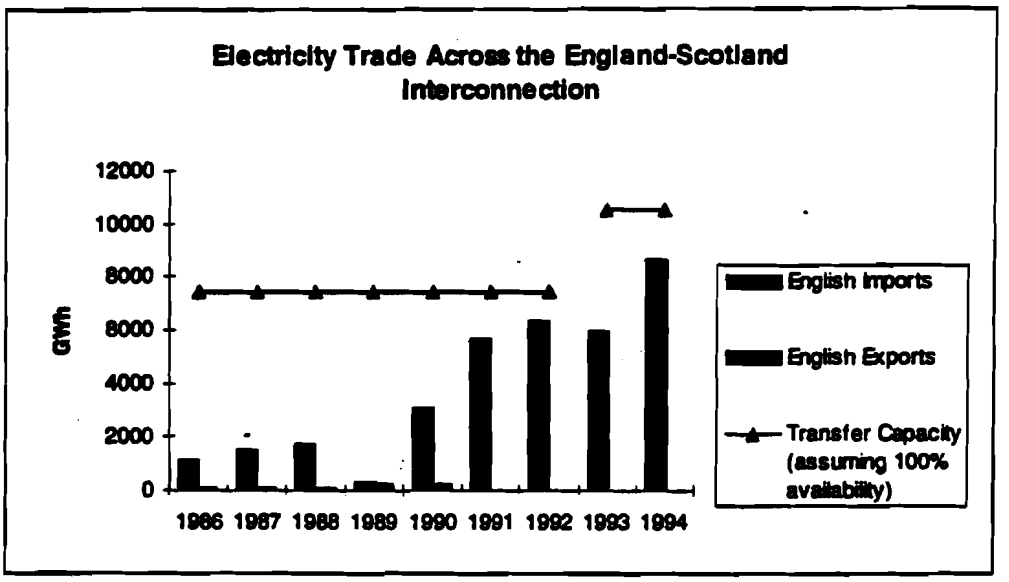
The Scottish industry was privatised in 1991 in the from of two vertically integrated electricity companies - Scottish Power (the successor to SSEB) and Scottish Hydro Electric (the successor to NSHEB). In both systems, nuclear power stations were retained in public ownership.

The Scottish and English electricity grids have been interconnected since the 1930s. Prior to privatisation trade across the interconnection was handled bilaterally between CEGB and SSEB. Following privatisation, trade has been conducted through the England and Wales Electricity Pool.

Pre-1970, energy flowed primarily from the CEGB to SSEB. This began to be reversed during the 1970s with the commissioning of the large modern generating sets at Cockenzie and Longannet. Through the early 1980s, Scottish exports of electricity generally varied between 1000 GWh to 2000 GWh. This increased dramatically during the miner's strike in 1984-85. The CEGB and SSEB agreed special arrangements to cover this period, and Scottish exports peaked at 6800 GWh in 1984/85. This amounted to some 20% of the total electricity generated in Scotland.

Exports again declined following the end of the strike, and remained at their historical levels until privatisation. Following privatisation, electricity trade has increased dramatically from 1161 GWh in 1986 to 8606 GWh in 1994.

The share of imports from Scotland and France in England and Wales generation has correspondingly increased from 3.2% in 1986/87 to 7.1% in 1990/91 and 8.1% in 1993/94.



This paper examines the factors underlying the increase in trade. The clear turning point in electricity trade has been privatisation. Prima facie, it would appear that the increase in trade has been stimulated by the change in incentives - the interconnection, plant availability and fuel mix remained broadly similar either side of privatisation.

The level of trade across grids depends on a number of factors. First, there must be a physical link across which electricity can flow. The interconnection between England and Scotland is discussed in Section 2.

Second, there must be a basis for trade. At minimum, there must be excess capacity in one system over some part of the demand profile. In other words, there must be capacity that can be traded. Section 3 highlights the level and source of excess capacity in the Scotland and England electricity systems.

Third, there must be a trading system through which trade can be organised. Pre-privatisation, English-Scottish trade was organised administratively. Post-privatisation, trade has been organised through the England and Wales Pool, and through bilateral contracts between generators and suppliers. These issues are discussed in Section 4.

Section 5 evaluates the trading experience across the England-Scotland interconnection, highlighting the key variables that have influenced the direction and level of trade both before and after privatisation. Section 6 concludes.

2. The Interconnection between England and Scotland

An interconnection has existed between Scotland and England since the 1930s, originally at 132 kV. The capacity of the interconnector was increased to 850 MW in the mid-1960s, remained at this level through privatisation, and was upgraded in 1993. For most of the post-war period, the major objective of the interconnection has been to enable the SSEB and the CEGB to assist each other at times when system security is under threat.

The interconnector comprises five circuits. Pre-privatisation it was operated by the SSEB and CEGB. Following privatisation, the interconnector is operated by Scottish Power and the National Grid Company (NGC) in England and Wales.

Table 1. Physical characteristics of the England - Scotland interconnection

	Voltage	Linking
1	2 x 275 kV	Harker, Cumbria and Strathaven, Lanarkshire
2	275kV	Cockenzie and Stella, Tyne and Wear
3	400kV	Torness and Stella
4	132kV	Chapelcross to Harker

The specific capacity available on any one day depends not only on maintenance plans, but also on the pattern of Scottish generation. For example, the 850 MW capacity varied between 500 MW and 1200 MW depending on system operating conditions. At present, the most significant factor influencing interconnection capacity is the output of the nuclear plant at Torness.

A joint CEGB/SSEB/NSHEB review of future trading in August 1985, looked at the case for increasing the capacity of the interconnection. The working group concluded that the cost of upgrading and reinforcing the transmission system to 1500 MW could not be justified by the potential benefits of increased trade.

The subsequent increase in trade, however, has led to agreements to upgrade the interconnection. In 1993, the capacity of the interconnector was upgraded to 1200MW. Upgrading work in the summer of 1993 temporarily

disrupted the operation of the interconnector, leading to a small decline in Scottish exports.

In practise, transmission constraints in Northern England have prevented full exploitation of the interconnection upgrade. NGC are currently reinforcing the transmission system in Yorkshire. The system reinforcement has yet to be granted all the necessary planning consents and wayleaves. A public enquiry is currently under way. NGC hope to complete system reinforcement by late 1996.

NGC, Scottish Power and Scottish Hydro Electric have agreed to further upgrade the capacity of the interconnection. Originally, this envisaged an upgrade to 2200 MW by the winter peak 1996/97. This timetable may be delayed by the transmission reinforcement work in Yorkshire.

An ancillary benefit of the interconnection between Scotland and the much larger England and Wales system is that frequency is stabilised in the former through synchronisation with the latter.

3. Excess Capacity as a Basis for Trade

3.1 The Incentive to Build

The post war electricity industry was characterised by capacity shortages and brown-outs, and increasing energy demand. These motivated industry planners to invest in additional generating capacity. However, capacity construction was not reduced during the 1970s as demand faltered following the oil price shocks. Demand forecasts produced by the CEGB and the Scottish Boards were consistently optimistic.

The industry desire to build was supported by the political desire of successive British Government's to protect domestic power plant manufacturing industry. The Government specified not only that the CEGB should buy domestically manufactured plant, but also dictated the timing of plant orders regardless of capacity. Thus, oil fired plants ordered during the 1970s were not cancelled despite the oil price shocks,[1] and were subsequently mothballed. The nuclear power stations at Heysham and Torness and the Drax I plant were ordered in advance of need. Protectionism not only fed excess capacity, but also led to relatively expensive plant. Plant construction times were long and rarely on schedule. The cost of plant construction was high compared to international experience.[2]

3.2 Excess Capacity in Scotland

By the mid-1980s, excess capacity was such that some plant were surplus to requirement. At the time of the MMC report in 1986, SSEB estimated a minimum reserve margin of 28% above the forecast 'average cold spell' demand. In the mid-1980s, capacity was some 20% in excess of this minimum requirement, and was expected to rise to almost 30% when the Torness nuclear plant became fully operational in 1990. The MMC noted that the excess capacity was a legacy of investment decisions taken on demand forecasts that were too optimistic.

The decision to build Torness was taken in the knowledge that it would add to excess capacity. It was considered that despite this there would be financial benefits to consumers and would help develop nuclear plant design and construction.

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1 See Select Committee on Energy, 1980/81 session, ' The Government's Statement on the New Nuclear Programme'.

2 See Alex Henney, 'A Study of the Privatisation of the Electricity Supply Industry in England and Wales', 1994, p32; and Select Committee on Energy 1980/81, p35.

Excess capacity raised the issue of whether surplus plant should be mothballed or retained for trade. The SSEB suggested at the time of the MMC enquiry in 1986 that if plant was retained simply for export, they would charge CEGB the costs associated with maintaining the availability of that plant.

At privatisation, installed capacity in Scotland totalled 12 GW. Maximum demand in 1988/89 was only 5.5 GW. Of this, the maximum demand facing SP was 4 GW and SHE 1.5 GW. Total sales in 1989 were about 30 million MWh, implying an average plant load factor of about 30%.

Assuming 1% growth in demand, however, new generating capacity would not be required in Scotland until 2005, when some of the existing plant begin to be withdrawn. At the time of the MMC enquiry, SSEB expected excess capacity until 2000, though at progressively lower levels.

3.3 Excess Capacity in England and Wales

The CEGB had a poor planning record throughout the 1960s and up to privatisation. Capacity forecasts were consistently optimistic. Excess capacity peaked in 1975 at 42%, double the minimum reserve required for operational purposes. The CEGB preference was to build large fossil fuel or nuclear plant.

Interestingly, the Select Committee on Energy (1980/81) emphasised that the independent development of the Scottish and English systems compounded the risk of over-investment, and given the interconnection, recommended a fully integrated planning system. Regardless of these suggestions, the Scottish and English systems continued to be planned independently of each other (see below).

The CEGB announced in its 1985/86 Annual report that "... CEGB has moved out of the period of plant surplus that has characterised recent years and into an era when we must plan for and get on with installing additional capacity. That capacity will be required irrespective of which fuel is chosen." (p6). This message re-echoed in the 1986/87 Annual Report - "Taking into account all the contributions from existing CEGB plant, from new stations already under construction, and from external sources including the French and Scottish interconnections, a total of about 10 new stations... could be needed by the year 2000" (p7).

In the late 1980s, the CEGB initiated plans to increase generating capacity with 3 PWRs in addition to Sizewell B, and 2 or 3 new coal fired plants each with a 1800MW capacity (see Henney, p36). These plants were all cancelled at privatisation.

4. Organisation of Trade

4.1 Pre-privatisation

The basic principles governing trade were set up in 1955. Both the Scottish and English generating systems were planned on the assumption that these would be no trade. Capacity offered for export was deemed to be surplus to internal requirements, and therefore no capital charges were included in the costing of trade offers.

Under normal trading conditions, trade was based on comparing export and import offers by the CEGB and SSEB over 'quotation periods'. Each 24 hour period was divided into a number of quotation periods with relatively similar demand conditions.

Both trading parties would make export and import offers for each quotation period. Export offers would be costed at the marginal cost of generating and transmitting energy to the border *after* satisfying internal demand. Similarly, import offers were based on the potential cost saving of not running domestic generating sets less the cost of transmission losses from the border.

Trading was not a specialised function but the responsibility of the general operating staff at SSEB and CEGB. Trade under normal conditions was planned a day ahead. Each Board would schedule, in merit order, sufficient capacity to meet forecast demand plus a reserve margin. Surplus plant could then be offered for exports. Import offers were based on the costs of the reserve plant. Given the relative size and complexity of plant scheduling in the CEGB system, the general practise was for SSEB to quote first.[3]

Comparison of the export and import offers determined the volume and direction of trade for each quotation period. The price at which energy would actually be traded was the mid-point between the two offers. In other words, the benefits from trade would be shared equally between the CEGB and SSEB.

The agreed trading price would be applied retrospectively to the actual flows of energy. In addition to the energy payment, the importer would expect to pay the exporter's start up costs, if the plant was specifically run for export, any running costs and variable maintenance costs.

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[3] Between November 1985 and February 1986, plant data for generating plant that exported regularly, was incorporated into the CEGB GOAL scheduling programme on a trial basis.

Prior to privatisation, the NSHEB and SSEB were subject to a joint generating arrangement, under which energy was despatched on an all-Scotland basis, and the costs and revenue allocated ex poste between the two Scottish Boards. Whilst trade was handled by the SSEB, the shared savings were split between the two Boards though the joint generating arrangement.

Trading arrangements outside 'normal' conditions were somewhat different. For example, where the alternative to trade was to spill dam water (or burn Peterhead gas), CEGB was obliged to import energy from SSEB, subject to system constraints. These imports were priced at the importer's marginal production cost. In other words, all the gains from trade would accrue to the importer (though the exporter would also benefit in that they would receive the import offer price rather than nothing for spilled energy).

Under the day ahead trading arrangement, if the importer refused imports, he would still be liable for the start up costs, and would pay for units at the previously agreed rate. In contrast if the exporter failed to deliver the agreed energy, there were no arrangements to compensate the importer.

4.2 Post-privatisation

Following privatisation, trade across the interconnection is organised through Scottish Hydro-Electric and Scottish Power's external membership of the England and Wales Pool. To ensure effective central despatch by the National Grid Company, all electricity produced for public supply has to be sold through the Pool.

In Scotland, SP and SHE are largely responsible for their own despatch, but can trade with each other. This is backed up by a licence obligation to purchase power at least cost. Energy traded through the interconnection, however, is subject to centralised despatch in line with the Pool rules.

Using the interconnector

Following privatisation, Scottish Power owns the interconnector, though contracts with Scottish Hydro Electric (SHE) and British Nuclear Fuels grant access in perpetuity. The contract with British Nuclear Fuels assigns rights to the Chapelcross circuit. The contract with SHE guarantees a transmission 'corridor' to SHE to wheel power through SP's network.

Prior to the upgrade of the interconnector in September 1993, SHE had access to 46% of the export capacity (less 46% of the Chapel Cross circuit assigned to British Nuclear Fuels). This amounted to an average capacity of 327 MW assuming interconnection capacity of 850 MW and 140 MW for the Chapelcross circuit. The remaining of capacity was assigned to SP.

Agreements between SP and SHE specify that SHE's share of any upgrade is to be settled by negotiation around a norm of a 25% share. Following the upgrade in 1993, SHE's allocation was fixed at 39.88% of the export capacity (less 46% of the Chapel Cross circuit assigned to British Nuclear Fuels).

A further contract with the National Grid Company governs the use of assets on the England and Wales side of the interconnector. This contract grants exclusive rights to SP and SHE to transfer electricity and/or to sub-contract these rights.

SP and SHE are required to prepare annually a week by week schedule showing:

- the anticipated total capacity for the transfer of electricity to and from England and Wales;
- the proportion of that capacity to which SHE has a right; and
- a forecast of the proportion of the remaining capacity required by SP.

SHE's agreement with SP provides for an annual fixed charge for the use of SP's transmission system and a capacity charge for the use of the interconnector. The fixed charge is linked to the RPI and depends in part on the interconnection capacity available to SHE during the contract year. The capacity charge includes a proportion of maintenance and other operating costs associated with the interconnector, as well as amounts for depreciation and a return on assets employed. No additional use of system charges are payable by SHE.

Trading through the England and Wales Pool

All energy flowing through the interconnection must be traded through the England and Wales Electricity Pool. Any generator trading through the interconnection must be an External Pool Member. External membership gives access to the England and Wales electricity suppliers, namely the Regional Electricity Companies (RECs). Additionally, obtaining Second Tier licences allows the External Member to supply power directly to customers in England and Wales.

External Pool Members are required to make offers to generate on a day ahead basis. They are different from the English generating companies, however, in that they are not connected directly to the England and Wales transmission grid, and therefore bid in a series of blocks of power at varying prices and availabilities, rather than individual generating stations.

The rights of the External Pool Member to interconnection capacity and their trading offers must be verified by SP. Subsequently, SP are also responsible

for the despatch of the traded electricity upon instructions from the Pool authorities.

Externally connected Members must therefore pay not only use of system charges for the interconnection, but also membership charges for the Pool and service charges to SP for the verification and despatch of traded electricity.

Independent Access to the Interconnector

Independent generators wishing to use the interconnector must apply to the SP if they would like an entry or exit point located in SP's authorised franchise area. SP are required to either make an offer for the use of the system or to inform the regulator that there is insufficient capacity to accommodate the applicant's request. In the latter case, SP may be required to provide sufficient information to the regulator and the applicant to determine the cost of upgrading the interconnection and the charges that would apply once the interconnector was upgraded.

Where the entry/exit point specified by the applicant is located in SHE's franchise area, the application should be directed to SHE. Disputes over terms for the use of the interconnection are to be resolved by the regulator.

To date there has not been a dispute over allocation of interconnector capacity, and no referral to the regulator.

Charges for the use of the interconnection cover entry, generation related infrastructure, demand related infrastructure, system service, and exit. The allocation of charges between these elements depends on whether the interconnection is used for imports or exports and the point of entry and exit.

Post privatisation, the capacity of the interconnector has been essentially allocated to SP, SHE and British Nuclear Fuels. The contractual system governing the use of the interconnection, the limited powers of the regulator over the allocation of that capacity, and the ability of the existing users to determine charges for the use of the system ensure that it will continue to be very difficult for new Scotland-based generators to trade through the England and Wales Pool.

Indeed, the Use of Interconnector Agreement setting out the Access and Allocation Code emphasises that the interconnector is already heavily used, and that prospective "users should not assume that allocations of existing capacity will be readily available" (para 5.2.5).

Contracts for Differences

At privatisation, many RECs entered into 'contracts for differences' with generators. These financial contracts specified delivery of energy at a pre-

determined price referenced against the pool price. Effectively, these contracts reduced the exposure of generators and suppliers to unforeseen movements in the pool price. Furthermore, Government urged the Regional Electricity Supply companies to enter these contracts with National Power and PowerGen so as to cover the long term fuel contracts signed with British Coal at above world prices.

SP and SHE also entered CFDs, though they were not subject to the same pressures as contracts signed between the English RECs and generators. The contracts signed by SP and SHE covered 178 MW and 100 MW of capacity, respectively, for one year. This was far below the capacity available to them on the interconnection, and represented a commercial decision to wait and see how the Pool developed.

In 1991/92, CFDs signed by SP increased to cover 320 MW of capacity, against their 350 MW share of the interconnector.

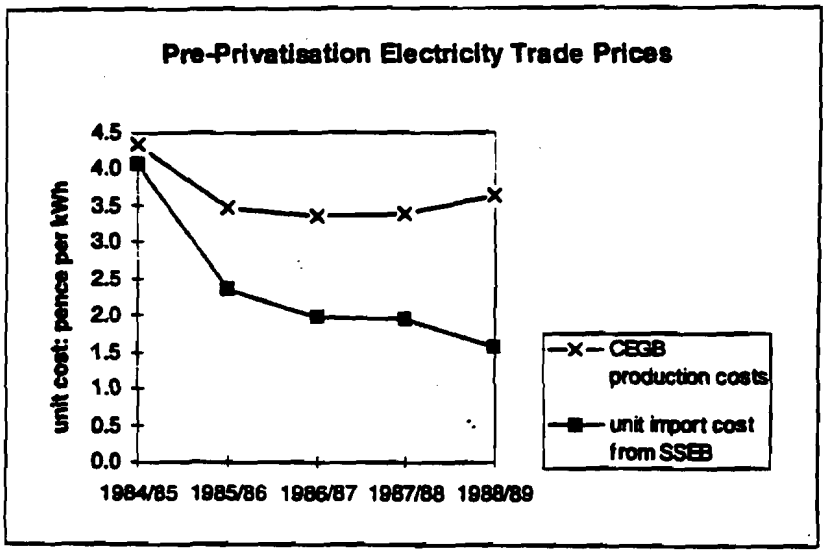
A number of contracts were also signed with large industrial consumers in England and Wales. The most significant of these was a major contract between SP and British Oxygen covering electricity supplies over a 6 year period beginning in 1991.

5. Evaluating the trade experience

5.1 Pre-privatisation: Was Trade Driven by Marginal Costs?

The pre-privatisation trading system was based on the marginal costs of the English and Scottish systems. The key question then is whether differences in marginal costs did indeed drive trade?

The little evidence available on this does show, for example, that the unit cost of electricity bought by the CEGB from the SSEB was well below the unit cost of producing electricity. The only exception to this was during the miner's strike when, as already noted, special circumstances applied.



The Thermal Efficiency of Scottish Plant

Before 1970 energy flowed primarily from the CEGB to the SSEB. This began to be reversed in the 1970s following the commissioning of large and modern generating sets at Cockenzie and Longannet. At full capacity, these sets operated at a higher thermal efficiency than the generally smaller sets at the margin of the CEGB system. Hence, for example, in 1987/88, the average availability of high merit coal fired plant at Cockenzie, Longannet and Kincardine was 75.1%, and the average thermal efficiency at Longannet was 37.55%. This contrasted with the average thermal efficiency of CEGB owned fossil fuel plant of 35%.

Consequently, through the mid-1980s, SSEB's exports largely comprised coal fired plant - Cockenzie and Kincardine during the day, and Longannet at night. These displaced oil or smaller coal fired plants at the margin of the CEGB system.

Published Information

The discussion of electricity trade in successive Annual Reports published by the CEGB suggest that trade may in fact have been driven by marginal costs. For example:

- a number of factors have affected potential imports from SSEB since the miners strike. "The commissioning of the Drax and Dinorwig power stations together with the contribution made by the AGR power stations under construction have reduced production costs on the CEGB's system. In addition, following the new agreement with British Coal, marginal supplies of electricity from the SSEB have become significantly less attractive in price terms". (1986/87 Report)

- imports from EdF (governed by similar trading arrangements as with SSEB) continued to increase as they are profitable, despite the fall in CEGB's coal ana energy costs. Imports under long term agreements covered 1000 MW and short term agreements covered additional flows. Trade with EdF displaced marginal oil fired generation helping to maintain the CEGB's oil burn at a low level. (1986/87 Report)

- imports from EdF continued to increase. "The imports injected much needed power into the South of England, thereby reducing the need for running more costly plant." (1987/88 Annual Report)

- there was a 75% increase in imports in 1987/88 from SSEB. CEGB reported that these were mainly due to pre-arranged contracts to provide cover for planned CEGB maintenance. In contrast, "marginal supplies from SSEB had to compete for most of the year with relatively low priced oil fired generation from CEGB power stations". (1987/88 annual Report)

Furthermore, and perhaps most importantly, the MMC investigation into SSEB in 1986 found that differences in marginal generation costs between Scotland and England were relatively small. This led the MMC to suggest that despite the surplus capacity, there was no need for longer term agreements specifying levels of energy to be exchanged or committing a segment of the Scottish system to SSEB.

Were Import Offers Understated by the CEGB?

The fact that trade has increased dramatically following privatisation must show that either that non-cost factors have led to an increase in trade or that the cost assessments underlying trade were understated prior to privatisation. There is no conclusive answer to this question, though the

welfare consequences of admitting further countries are ambiguous because the reduction of distortions between some players (eg the Finns, if they are admitted to the joint market) would be offset by the increased distortions between the Finns and their other trading partners.

- Norway and Sweden will also need to develop a joint trade policy, and are trying to harmonise their import and export tariffs to third countries. The links to Holland and Germany are currently used mainly for exchanges, and it will be important to put such harmonised tariffs in place for long term exports to become feasible.

According to NUTEK (Swedish Electricity Market 1995, p15), the Swedish government thinks there is no need for increased control on international electricity trade in the short term, but that "opportunities should be available for placing certain restrictions on foreign trade .. if the reliability of supply should be threatened in the future". It therefore recommends:

- a special concession regime for imports and exports; and
- extending the obligation to notify long-term contracts

while recognising that trade must be regulated - if at all - in such a way as not to jeopardise its beneficial effects. A special investigator has been appointed to draw up proposals for new legislation in accordance with these principles.

discussion of incentives and the pre-privatisation trading arrangements show that such understatement may well have been possible.

However, it should be noted that:

- the difference in thermal efficiency between Longannet and the CEGB fossil fuel average was relatively small, though Scottish nuclear plant was more efficient;
- coal prices faced by both the CEGB and Scottish plant were similarly priced; and
- the MMC findings that marginal costs differed little between the CEGB and Scottish systems is the only published assessment of the trade record.

At the very least, we can conclude that whilst marginal costs did differ and may have been understated, it is unlikely that the true difference in costs was such as to stimulate the increase in trade that has taken place following privatisation. Other factors that may have contributed to the post-privatisation increase in trade are examined below.

5.2 The Pre-Privatisation Trading Arrangements

Before privatisation, both the CEGB and SSEB were obliged to supply electricity at least cost, and to trade on the basis of declared export and imports offers. However, given the bilateral nature of the trading relationship, and the general lack of accountability of the electricity industry (see below), the trading system was not transparent.

The costing of export and import offers was examined by the MMC report on SSEB in August 1986. The MMC found that neither the SSEB nor the CEGB had a detailed understanding of each others methodology in measuring the costs that underlie offers to trade. Furthermore, whilst the general practise was for SSEB to quote first, the MMC report found that SSEB did not know which plant were scheduled as reserve by the CEGB. In other words, they were unaware of which plants their export offers were competing against.

To compound the ad hoc nature of trade, the MMC found that neither the SSEB nor CEGB had a formal system to monitor trading across the interconnector.

Specific issues inhibiting trade highlighted by the CEGB and SSEB themselves (Value for Money study, and joint working party) included:

- the quotation period was generally longer than the half hour scheduling period. Hence, export offers for the whole quotation period were based on the peak half hour. Under such circumstances, the potential importer preferred to run expensive plant at peak times in preference to taking cheaper plant for the whole quotation period. The Value for Money study suggested that these circumstance should have led to CEGB requesting shorter quotation periods, but found that in fact this had not been considered.

- the imbalance of compensation arrangements for failing to honour day ahead trading commitments between importer and exporter was also highlighted as a potential deterrent to trade. Compensation arrangements effectively skewed the risk of trade in favour of the exporter.

In sum, despite the potential to trade, the MMC found that both the CEGB and the SSEB "start from the position that the development of each system is independent of trade... a detailed and comprehensive comparison of CEGB and SSEB costing has never been carried out.... Neither Board has an up to date trading manual for the use of control room staff involved in trading activities".

5.3 Incentives in the Pre-Privatised Electricity Industry

before privatisation, the electricity industry was characterised by political interference, lack of public accountability, public sector constraints and union militancy. In short, commercial bast practise was not always the key objective. Indeed, the lack of public accountability allowed the industry to take positions and pursue investment plans that were not always in the best interest of the consumer.

On public accountability, the 1980/81 Energy Committee Report delivered a damning assessment of CEGB's operating and investment policies. For example,

- "we would have greater confidence in the Board's argument if we were convinced that it addressed itself as vigorously to the economic case for investing in a programme at all, as it does to the relative merits of coal and nuclear.....";

- "we find the Board's cavalier attitude to price comparisons profoundly unsatisfactory...."; and

- "unless the CEGB are able to effect considerable reductions in their own costs, this country will continue to produce electricity more expensively than need be the case".

The Central Electricity Generating Board (CEGB) owned and operated over 90% of the 60GW of installed capacity. It despatched capacity in merit order and took supply across interconnectors with France and Scotland, giving it a monopoly in public supply. Distribution was handled by 12 publicly owned area distribution boards each with a geographical monopoly.

The structure of the industry gave CEGB inordinate market power. Simply put, the Area Boards were not in a position to challenge CEGB's bulk supply tariffs, and could simply pass on costs to their consumers (see Henney, p40). Under these conditions, and given political interference and a lack of public accountability, the CEGB's market power allowed it to make non-economic decisions without penalty or sanction.

The bulk of the fossil-fuelled generation relied on domestically produced coal at prices significantly above world levels. This formed part of the Government strategy to protect the coal industry and preserve national security of supply. Many large industrial customers were protected from the high cost of British coal through the Qualifying Industrial Customers Scheme. The cost of the subsidy was borne by smaller consumers.

Essentially, the CEGB operated on a cost pass through basis with no risk and no competition. The Government expected the CEGB and the Area Boards to make a minimum rate of return on their assets, while restricting their borrowing to meet overall fiscal targets, and expecting a reduction in controllable over a given number of years.

If the CEGB built a high cost station, the costs would be passed on to the Area Boards, who in turn could pass on the cost to final consumers without constraint.

In short, the desire to ensure adequate capacity, the lack of incentives to cost minimise and optimistic demand forecasts led to excess capacity. It can be argued that once the system had excess capacity, and given the ability to pass through costs to final consumers, the CEGB had little incentive to minimise energy costs through on going trade.

There was, however, every incentive to trade to add system security and to cover short term trade gains. These are precisely the trade gains that were captured by trade during the 1980s, prior to privatisation.

Many of the shortcomings of the electricity industry were due to a lack of accountability, and checks and balances such as those provided by competitive markets.

5.4 Privatisation in England and Wales

Privatisation has changed trading relationships in the electricity industry in two key respects.

First, greater commercialisation has led to greater responsiveness to consumers, new managerial dynamism, more market based generation planning.[4] In turn, competition reduced costs:

- capacity plans for 3 PWRs and 4 coal plants were cancelled. In practise, these were replaced by new CCGT capacity;
- commercial pressures led to lower coal fuel prices, and increasing coal imports;
- manpower levels fell;
- equipment and plant costs fell as the domestic industry was exposed to international competition;
- capital programmes have been more carefully appraised and subjected to commercial considerations. This includes transmission and distribution programmes; and
- costs and prices in the industry have become subject to much closer scrutiny.

Competitive pressures have similarly led electricity suppliers in England and Wales, as well as large industrial users, to seek least cost supplies of electricity. The benchmark for these supplies is the Pool price.

Second, the unbundling of the industry changed the balance of power in negotiating trade relations. Where the Scottish generators were previously negotiating trade with the CEGB, post privatisation trade was conducted with RECs and large industrial users, where each was an independent business entity not significantly larger than the Scottish companies..

Privatisation in Scotland

Scottish generators were generally keen to export prior to privatisation. This reflected a desire to run their excess capacity. Privatisation of the Scottish industry increased the commercial incentive to trade, and access to the Pool created an opportunity.

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[4] See Henney, 1994.

The SSEB's Annual Report in 1987/88 declared that "SSEB are gearing themselves to meet the opportunities that will come with privatisation.... Torness on stream plus privatisation will allow the Board to exploit export opportunities..".

The 1989/90 and subsequent Accounts published by both SP and SHE highlight the potential benefits from increased exports. The 1989/90 statement by the SHE chairman argues that "an important feature of privatisation is the opportunity for Hydro Electric to trade more widely with other electricity companies".

In 1990/91, SP's Annual Report highlighted that the plan to upgrade the interconnector would "allow opportunities for significantly improved utilisation of generating plant from 1993 onwards"; and SHE's 1994/95 Annual Review notes that the rise in interconnection capacity will increase "utilisation of our Scottish generation will be raised almost to its optimum level later this decade".

In their first year of business, 1991/92, SP reported that they used their share of the interconnector at almost 100% capacity, and exported 21% of the electricity they generated, and expected this trend to continue subject to the upgrade of the interconnection capacity.

SHE's 1994/95 Annual Review notes that since 1990 the volume of electricity trade has increased by 124%, and that sales to England and Wales account for 31.5% of sales volume and 25% of turnover.

In short, the evidence suggests that the Scottish companies have sought to maximise trading opportunities both before and after privatisation. The reason for this lies in the nature of the generating capacity available to them.

5.5 The structure of Scottish generating capacity

At privatisation, the thermal efficiency of Scottish plants was generally higher than equivalent plants in England and Wales. Similarly, the load factors achieved by Scottish nuclear plant were much higher than their English counterparts. Furthermore, coal available to the Scottish generators was more efficient as it had a lower sulphur content, and there was less uncertainty over coal supplies.[5] Cost differentials, however, may have been far less significant than the large excess capacity in the Scottish system.

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[5] For example, a long term coal contract governed supplies to the Longannet plant at a time when generators in England and Wales were continually seeking to re-negotiate contracts with British Coal or to import from other sources.

The Scottish electricity industry is characterised by heavy excess capacity. This combined with the hydro capability, the must-take contract governing gas supplies to Peterhead, and contracts to take nuclear power from Scottish Nuclear, means that excess energy is an on going feature of the Scottish system.

SHE are contracted to take all the gas over the lifetime of the North Sea Miller field for use in the Peterhead power station. The installed capacity at Peterhead is 1320 MW. At its peak, this generates 13 million MWh per annum - total sales of electricity in 1989 were about 30 million MWh. Some of the Peterhead capacity is contracted to SP. The arrangements governing Miller gas dictate that all the gas received must be burnt.

SHE and SP have also contracted to purchase all output from Scottish Nuclear's plants. The companies are obliged to pay against declared availability even if they do not take energy. Moreover their payments reflect the level of availability declared by Scottish Nuclear. Effectively, the contracts with Scottish Nuclear are structured so that SP and SHE have very strong incentives to take their full entitlement of electricity.

Scottish generating capacity is not only in excess of domestic requirements and governed by must take contracts, but is also 'lumpy'. For example, the installed capacities of a number of major plant are:

- Cockenzie (coal fired) has an installed capacity of 1200 MW;
- Longannet (coal fired) 2400 MW;
- Peterhead (gas/oil fired) 1320 MW;
- Inverkip (oil fired) 2028 MW
- Hunterston B (nuclear) 1320 MW; and
- Torness (nuclear) 1364 MW.

These installed capacities contrast with maximum demand in 1989 of 5500 MW.

SHE are particularly prone to excess energy. A Trading Code with SP has been designed to ensure that merit order despatch proceeds on an all Scotland basis. This ensures that SP buys hydro power from SHE rather than spilling hydro water and generating itself. Upgrade of the interconnection should allow more of this spill to be exported.

The excess energy in the Scottish system, plus the lumpy nature of that capacity give SP and SHE a strong incentive to export to maximise revenue even if the unit cost of those exports is below the long run marginal cost of supply.

This is borne out by the bidding behaviour of SP and SHE in the England and Wales Pool. In general, they have been happy to bid zero. In other words, to ensure despatch and receipt of the system marginal price.

These incentives are supported by the fact that at privatisation much of the excess capacity was effectively treated as sunk costs. Given that the authorities decided not to push the burden of the sunk cost onto the consumer, the market discounted the value of SP and SHE's assets at privatisation. The market capitalisation of SHE at privatisation was 48% of the book value of assets (on a CCA basis), and 67% of book value for SP. In other words, providing an adequate return on shareholder funds does not require pricing energy to reflect the full value of the underlying assets.

Furthermore, the vertically integrated nature of the Scottish system and the lack of competition in the franchise area allows SP and SHE to price energy exports at the short run marginal cost. Within Scotland, SP and SHE are essentially monopolists over the franchise consumer market, and duopolists in the non-franchise market - the capacity of the RECs to compete in the non-franchise market is limited by the capacity and nature of the interconnection. Specifically, energy can only flow one way at a time across the interconnection; hence, if cheap exports are competitive in the Pool, the competitive pressures in the England and Wales Pool will not allow the RECs or the English generators to price electricitv so as to change the direction of trade.

5.6 Scottish imports

The lack of competition to supply electricity in Scotland does not imply that SP and SHE cannot import from the Pool if the pool price is below their marginal cost. Indeed, in the first few months of the operation of the Pool, SP and SHE did import substantial quantities of electricity, principally at night, taking advantage of the low pool prices that prevailed at that time. Pool prices were low because National Power and PowerGen were committed to coal purchases from British Coal and bid low to ensure that there plant ran. On the Scottish side, electricity imports were especially attractive given the avoidable cost of shutting down large plant at night time and avoiding running high cost smaller plant. Subsequently as pool prices rose, imports declined to almost nothing.

5.7 The Non-Fossil Fuel Order

At privatisation, the Government provided for the excess costs of nuclear generation and environmentally desirable renewable sources through the non-fossil fuel obligation. Under this, each REC is obliged to purchase a given amount of electricity from non-fossil fuel sources.

To recover the excess cost of purchasing electricity generated under the NFFO, all sales of electricity are subject to the fossil fuel levy. This is currently 10%. However, electricity bought from the Scottish generators is generally not subject to the levy. In other words, Scottish exports of electricity have enjoyed a tax advantage through the post privatisation period.

The importance of this as a driver for trade should not be under estimated. Indeed, this is highlighted as a key issue in the privatisation prospectuses issued by National Power and PowerGen in February 1995. National Power note that "the fossil fuel exempt status of electricity imports from France and Scotland make them competitive as import only capacity". And PowerGen argue that "net flows through the interconnection principally depend on the extent to which supplies associated with imports form France and Scotland continue to be exempt from the fossil fuel levy". At the time of privatisation, both National power and PowerGen expected imports to increase due to this tax advantage.

It has been recently announced that the NFFO system and the levy will be abolished during 1996. The mechanism that will replace the NFFO, if any, has not yet been made public. It will be interesting to see what trade effects follow from this change.

6. Why Did Trade Increase Following Privatisation?

Privatisation changed the structure of the electricity industry irrevocably. Greater commercialisation and competition have led all participants to seek to maximise trade opportunities. The opportunity to trade, however, in itself is not enough to increase trade. There must be a basis for trade.

Trade in electricity before privatisation was based on and may well have accurately reflected the underlying marginal costs of the English and Scottish systems. Whilst plant in Scotland enjoyed higher thermal efficiency, they do not appear to have been significantly cheaper. In other words, the level of trade between the systems reflected the nature of the trading arrangements.

The change in arrangements following privatisation allowed Scottish excess capacity and vertical integration to enter the equation. Essentially, the increase in trade between Scotland and England has been driven by mistakes in the past - over optimistic demand forecasts and over-ambitious capacity expansion in Scotland - and the form of privatisation chosen for the industry in Scotland.

Scottish exports will continue to be competitive so long as excess capacity remains in the Scottish system, and the industry structure in Scotland prevents increasing competition from England and Wales based suppliers.

A more insightful evaluation of trade between Scotland and England must, therefore, await the end of excess capacity in the Scottish system. The key trade issue will whether a commercial generating company will invest in plant specifically for trade purposes? The answer to this remains to be seen.

Regional Grid Networks 2

Case Study 2 : Norway - Sweden Case Study

Norway - Sweden Case Study

Table of Contents

Norway - Sweden Case Study

1. Introduction

Norway and Sweden have strong interconnections and a history of power exchanges under the co-operative Nordel arrangement between the Nordic countries (established in 1963) and its precursors. Their power systems are complementary in that Norway is almost wholly hydro-dependent while Sweden has a mix of thermal, nuclear and hydro capacity. There are considerable electricity flows in both directions, but the balance of trade is for Norway to be a net exporter to Sweden. Sweden is a net exporter of power to the other Nordic countries, and maintains a rough balance overall.

Norway opened up its Pool system in 1991, bringing in competition in generation in its domestic market. This has also affected regional electricity trade, and has been followed by the creation of a Pool by Sweden at the beginning of 1995, and similar moves are underway in Finland. Trade in electricity between Norway and Sweden provides interesting evidence of the interaction between institutional arrangements and international power trade, in several respects:

i) in the period up to 1991, when Norway and Sweden operated somewhat similar non-market systems for dispatching electricity within their own systems, they achieved a high degree of interconnection and mutual electricity trade under the Nordel "club" arrangements. However it is not clear that the trade that took place under those arrangements was necessarily of maximum economic advantage;

ii) in the period 1992-95, when Norway had liberalised its internal market and established a competitive power pool, but Sweden continued to have a non-market system, trade was initially administratively restricted from both sides, which led some commentators to suggest that unilateral liberalisation might be harmful for trade. Subsequent developments however tend to suggest that this is not in fact the case;

iii) from the beginning of 1996, Sweden has adopted a similar set of market reforms to those in Norway. It is too early to know what effect this will have on the trade between the two countries, but developments in this market will continue to be of key importance for understanding the interaction of structure and trade. In particular, Sweden and Norway have adopted slightly different versions of spot transmission prices, and it will be important to see what impact this has on trade;

iv) institutional change was not accompanied in either country by significant changes in ownership. This makes them an ideal "laboratory" for separating the effects on international trade of reorganisation from those of ownership change; and

v) both countries have emphasised the importance of low-cost electricity supply, which has tended to favour a cost-conscious approach to expansion planning and trade, even though many important players in the electricity market are not cost-minimisers or profit maximisers in a formal sense.

This case study starts by describing the trade between the two countries under the Nordel system[1] and during the period since Norway's unilateral liberalisation. It goes on to examine the specifics of the market reforms in Norway and Sweden, and concludes by examining their prospective effects on electricity trade.

[1] The Nordel system is described in detail in the report of the previous project (The Development of Regional Electric Power Networks, London Economics June 1994).

2. The Nordel System

Nordel provides a framework for co-operation and co-ordination between the electricity industries of the Nordic countries, but has no formal powers. Its membership is limited to prominent members of the national electricity supply industries (generators and transmission/distribution companies). International trade has been conducted on the basis of informal bilateral agreements, under which system marginal costs were mutually disclosed and the gains from trade were shared.

Underlying this framework for international co-operation are a set of national electricity supply industries in the Nordic countries that differ considerably in terms of the installed capacity of different generating technology, organisation of the industry and interconnector capacity. However, all of the national systems have developed largely on the basis of negotiation and co-operation among the major agents, with only limited formal government regulation. All the countries have a mix of large and small, public and private utilities, though the lead in developing the industry has been to a large extent taken by one or more dominant public firms in each country:

- Norway's largest generator is the state-owned Statkraft. It has been unbundled so that the main grid is owned and operated by the state-owned Statnett, which also operates the Pool and owns and operates the international interconnectors. The remainder of generation capacity is either municipally or privately owned;

- Sweden's ESI is dominated by the state-owned company Vattenfall, responsible for half of its generation capacity. Vattenfall's generation and transmission functions have now been unbundled, the transmission assets being held by Svenska Kraftnet;

- in Denmark, municipalities took the lead in electrification and two completely separate grids have developed, one on the mainland (Elsam) and the other on the islands (Elkraft). Each area is characterised by close co-operation between its constituent utilities, with the grid companies responsible for operating generation as well as transmission; and

- in Finland, the ESI is dominated by the publicly owned IVO (generation and international connections) and IVS (transmission grid), but the privately owned TVO generators also own a private grid (TVS). The government has decided that IVS and TVS should run the transmission system jointly.

Under Nordel, trade operated on a large scale and with a considerable degree of success. For instance in 1990, Sweden imported 12.3 TWh of electricity from Norway, or about 9% of its total electricity use in that year, and exported an even larger amount to the other Nordel countries.

Trade however was not sufficient to equalise electricity prices in the markets even of strongly connected neighbouring countries, indicating that there were still potential gains to be made from increased trade. In 1989, for instance, industrial power prices were lowest in Norway and progressively higher in Sweden, Finland and Denmark.

Table 1 : Average price of firm power to industry (Norwegian Kronor per kWh), 1989

Norway	Sweden	Finland	Denmark
0.11	0.24	0.35	0.42

This suggests that the potential gains from comparative advantages in energy production (particularly the substitution of cheap Norwegian hydro power for expensive thermal generation in the other countries) were not being completely realised. If trade were open, a common price would emerge eventually, but the scope for governments to have independent energy policies would also diminish[2].

The Nordel arrangement constitutes a very "loose" pool, with day to day exchanges and frequency stabilisation based on informal agreements. In parallel, there are a few more formal long term contracts, the most important being between Norwegian sellers and Swedish and Danish buyers.

Short-run exchanges under Nordel are (or in the case of the trade between Sweden and Norway, were) based on the split savings principle, under which each operator informs its trading partner of its system marginal costs and the price is set as the average of the two systems. Prices are also capped, protecting buyers who face emergency situations in their systems. These arrangements prevent much exercise of market power, largely avoiding problems between the constituent systems. Only rarely has there been any suspicion that cost declarations have been manipulated - though for instance Norway asserts that Denmark overstates its system marginal costs in periods when it is exporting, while Denmark insists that Norway's exports of hydro power be sold as if they were surpluses whose opportunity cost would be to spill water from its reservoirs.

[2] This is an important implication for developing countries.

It has been more difficult for Nordel to achieve co-operation in areas where national control or self sufficiency were at stake or where the gains from trade seemed likely to be one-sided. Third party access to networks has been generally denied. A difficulty has also arisen of how to deal with Norway's surplus or occasional power in years of adequate water resources. Norway's Nordel partners seek to buy it on the basis that its marginal cost is near zero, but Norway argues that is worth much more than this because it can be used as regulating power in their systems. A more regulated common market would strengthen Norway's position on this issue, which was a major motivation in Norway for trade reform, and in Sweden and Denmark for retaining Nordel.

3. Trade under Unilateral Liberalisation in Norway

When Norway deregulated its industry in 1991, this was accompanied by a rapid decrease in Norway's power exports, and a question raised at the time was whether this decrease reflected strains on the international trading arrangements as a result of Norway's unilateral reform.

For example, Sweden initially refused to accept that Norway's Pool price fairly represented Norway's system marginal costs, and the mid-price arrangement governing Nordel trade between the two countries broke down. Further, Swedish and Danish buyers and sellers subsequently started to bid in the Norwegian Pool, and power exchanges came to be regulated according to the Pool merit order. This liberalisation of trade made exports more profitable and increased Norwegian producers' interest in exporting power. In 1992 the Norwegian Government stipulated a limit on power exports of 5 TWh/yr under contracts of from 6 months to 5 years duration, in order to avoid undue increases in Norway's domestic prices.

Another transitional problem was that clients in Eastern Sweden wanted to import from Norway but were prevented from doing so by Sweden's concession system if they were not actually adjacent to the border - the exclusive nature of the area concessions meant that they had no access to the intervening transmission links.

However, examining the scale of the electricity trade between the two countries over a longer period, it becomes clear that the level of trade in 1989 and 1990 was exceptionally high, and that the pattern that developed over subsequent years was not out of line with previous experience.

The scale of electricity trade varies from one year to the next, largely reflecting weather conditions and water availability and the resulting scale of Norway's exportable surplus. In 1989 and 1990, in particular, water availability was very high in both countries. Despite the high level of imports from Norway, Sweden was a net exporter of electricity within Nordel in both years. Conversely in 1994, for example, the volume of trade was affected by very low water levels in both Norway and Sweden. Norway's shortage made its power very expensive, and regional trade patterns became very untypical with both Sweden and Norway importing power from Denmark, which has a largely thermal system.

Table 2 : Electricity Trade between Sweden and Norway, 1987-1994 (TWh)

	Swedish Imports from Norway	Swedish Exports to Norway
1987	1.4	2.3
1988	4.5	1.1
1989	11.4	0.4
1990	12.3	0.4
1991	4.7	3.1
1992	6.7	1.2
1993	6.3	0.5
1994	4.5	2.8

Source: NUTEK "Swedish Electricity Market - from Monopoly to Competition, and "Swedish Electricity Market 1995"

The trade between Sweden and Norway has in recent years moved from being exclusively based on short-term temporary power (eg in 1990-92), to have a considerable component of contracted power (half of total trade in 1994 for instance). Several Swedish generators have agreements with generators in neighbouring countries for imports and exports of power; for instance Sydkraft has an annual purchase contract of 800 GWh/yr, and Vattenfall has a four-year agreement to purchase 2,400 GWh/yr, both from Norway.

Long term contracts currently account for 70-80% of total Norway/Sweden trade, and for 1/2 to 2/3 of interconnector capacity. They are given priority over spot trades, and have to pay a priority fee for this privilege. Kraftnat and Statnett decided what contracts to accept; the restrictions are mainly on the Norwegian side where exporters need licenses from the authorities.

Further bilateral contracts are not now being accepted, in order to make room for more spot transactions. Norway is thus moving its international trade from a pattern of short term transactions based on surplus capacity, combined with relatively restrictive long-term contracts, to one based on spot transactions between generators and customers, regardless of their nationality.

As this process supplants the more traditional forms of international trade, Nordel is moving to more of a technical co-operation forum and its importance is decreasing.

4. The ESI Reforms in Norway

One of the salient features of Norway's reforms is that (unlike the UK for example) they have not all occurred as a single overhaul leading to a fixed set of market rules and institutions. Rather they have taken place over a period of time and are still continuing to evolve. When Norway opened its pool, it was building on skills developed in using transparent marginal pricing with the closed pool since the 1970s. The liberalisation thus did not represent as large a step in Norway as it would have done elsewhere.

The introduction of the Norwegian Energy Act at the start of 1991 however did result in major changes in the organisation of the Norwegian electricity supply industry. It separated the monopoly from the competitive activities of power companies, terminated fixed contractual obligations to supply, and established both a new central network scheme and a market for independent buyers and sellers of power.

While Norway had had a Power Pool since 1970, which used the principle of trading at the price which balanced supply and demand, membership of the Pool was limited to power producers. The 1991 reform opened the Pool to consumers and suppliers, and gave all consumers the right to choose their power supplier at freely negotiated prices. It also imposed on the owners of distribution networks an obligation to connect up system users (third party access).

Norway did not, either before or after the reform, have a strong central institution to co-ordinate plant dispatch. Since all capacity is hydroelectric, all producers have variable operating costs near zero, and central dispatch co-ordination is not required to ensure that system variable operating costs are minimised[3]. Rather it is a commercial issue for power companies to decide how to value the water in their reservoirs, and the key issue is to ensure that only those plants are run that bid at or below the current pool price. The week-ahead market is intended to value water resources, and the increasing volume of trade in this market suggests that it has been successful.

The 1991 reforms were designed to address the problems of:

- over-construction of capacity by municipal utilities, which preferred to construct capacity rather than purchase contracts, leading to a wide dispersion of domestic tariffs;
- the development of increasingly expensive capacity by Statkraft (the major generator), in response to demand

[3] A significant tranche of demand consists of boilers that can be run on either oil or electricity, and ensuring that these burn oil only when the price of electricity is high is an important element of minimising operating costs system-wide.

forecasts, increasing its costs while it remained obliged to supply industry at low prices; and

- price discrimination by distributors in favour of households and against small and medium enterprises.

Since the beginning of 1993, the power market has been organised by Statnett Marked, a state owned concern which manages purchases and sales of power by producers and consumers, and runs a number of power markets (day-ahead, weekly or "futures", and regulating power) with the aim of ensuring a large volume of trades and a large number of "players" so as to guarantee competitive price outcomes, and of minimising transaction costs.

The termination of contracts between producers and end users has led to most electricity being traded through the markets. While some (eg short term) contracts continue, their prices increasingly use the day-ahead market price as a point of reference. The pool price fell sharply in the wake of liberalisation, but varies considerably because of supply side factors. In 1993/4 with a dry autumn and cold winter prices were high and in the wet summer/autumn of 1995 prices were relatively low. The dispersion of domestic prices has decreased, and their general level has fallen, both of which suggest that there have been static allocative gains from liberalisation. Meanwhile, investment expenditure has fallen, especially in generation, suggesting that dynamic efficiency gains are also being realised.

There are now several different kinds of players in Norway's markets, particularly:

- power producers;
- power distributors (normally small municipally owned utilities);
- vertically integrated companies;
- brokers (who cannot hold unbalanced contract portfolios) and traders (who can, and from 15/1/96 have been able to supply customers directly); and
- consumers, particularly large industrial users.

The total number of players in the market had increased from 57 in 1991 to 110 by late 1995. As the number of players has increased, so has the confidence that the market price represents a competitive equilibrium, with its attendant economic efficiency benefits.

Financial pressures on power companies have led to their adopting a more commercial attitude, including responsiveness to customers in offering suitable pricing arrangements, cost cutting, and improved risk management.

The success factors for the Pool have been:

- neutrality, ie the assurance of no price manipulation;
- access for all types of player, ie the same type of contract for all;
- enough players;
- low transaction fees (falling as the number of transactions increases);
- liquid markets (even though bilateral trades are continuing in parallel); and
- full information (historical data only).

The spot market accounts for about 25% of physical power flows, though it is difficult to be exact since the same contract may be traded several times. The smallest contract size is 0.1 MW.

Structural changes continue to occur within the Norwegian power pool and markets. Up to October 1995, the weekly market was for physical delivery, and had weekly settlement. Then it changed to become a pure electricity futures market, with trades up to 2 years ahead and daily settlement. It is the first functioning electricity futures market in the world[4]. The form of contract is based on what had been developed in the Pool for the typical loads of distribution companies[5]. All profits and losses have to be settled daily by the Oslo Futures and Options Exchange. A trader's position is closed if he cannot meet the losses he has incurred, and his contract portfolio would be resold on the market.

The greatest volume of trade is for basic load (trading up to 2 years ahead), while Night and Day power are traded only up to 1 year ahead. The trade is on a weekly basis for the coming 7 weeks, then by 4 week blocks up to 1 year, then by seasons (high and low).

The day market: Statnett is committed to buy about 200 MW of Main Grid losses at any price. Zero supply bids are submitted by those distributors and other customers who have bought more bilaterally than they actually need and want to resell to recoup some of their costs.

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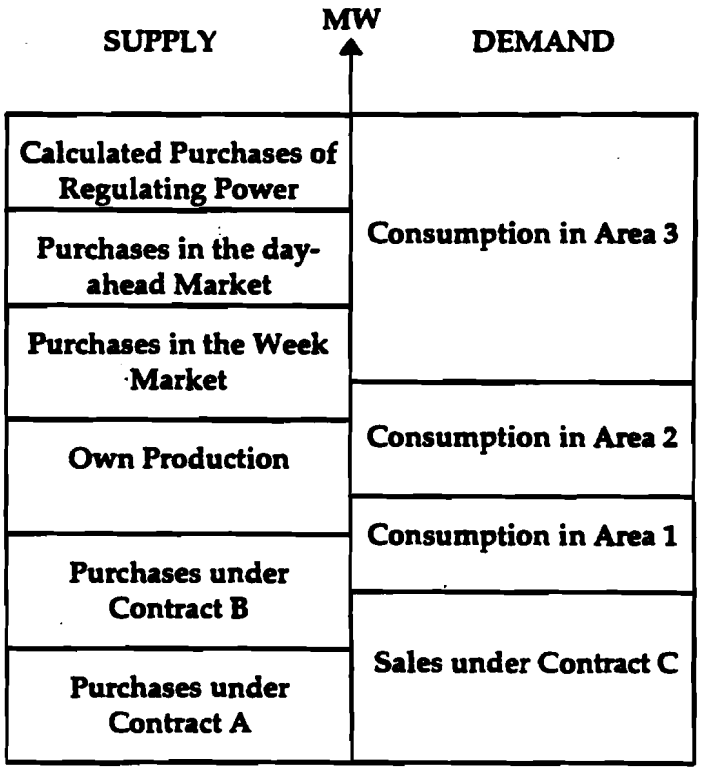
[4] The New York Mercantile Exchange (Nymex) is expected to start one in 1996

[5] The Nymex contract will be similar

The regulating market: This market exists to handle short term supply-demand imbalances. It is based on bids for increments and decrements in generation output, and is a physical market. Customers demand side measures can also be bid in.

At the end of each week, players in the four markets have to declare their behaviour, bilateral and physical, and this has to be reconciled with Statnett Marked's information on trade in the markets. Any difference between aggregate supply and demand is settled at the marginal price in the regulating market.

Figure 1: Calculating Purchases of Power in the Regulating Market



The day and regulating market prices are on trend very close to each other, with some day to day variation but almost identical weekly averages.

The regulating market has a volume of around 100 MW, while the weekly market had increased from 100 MW at the beginning of 1995 to 400 MW by November 1995. The spot market volume was around 300 MW until the weekly market moved to a financial basis; it then rose to about 700 MW. This is thought to be because some vertically integrated companies have moved trading between their production and distribution arms to the spot market.

4.1 Transmission Pricing in Norway

Prior to the 1991 Energy Act, transmission prices were based on the distance between generating plant and the customer, and a transport element was included in the actual electricity price. In 1992 this was replaced by a node-based system, under which:

- both customers and generators have to pay for the use of the transmission network;
- network owners have a duty to calculate the price for the input and output of power; and
- paying the price established for a connection point gives access to the entire network and electricity market.

Statnett first calculates the Main Grid tariff. Regional networks then set their own tariffs, including their costs of access to the Main Grid, and the tariffs for their areas are based on the total of these two cost elements.

The transmission prices in this system are a simplified version of theoretically efficient nodal prices, under which the country is divided into 5 areas rather than trying to price access at each of the 200 or so grid connection points. Each tariff has both:

1. a variable element, consisting of an energy fee and a bottleneck or transmission capacity fee; and
2. a fixed element, composed of connection and power fees.

The energy fee: This covers losses, based on typical power flows and system loading. It is defined for five tariff areas and three representative time periods, and for 3-4 representative input and output points in each area. It varies considerably over time and from one part of the country to another.

The capacity fee: When a transmission bottleneck is foreseen, the information is passed on to the market in the form of a map. Traders then have to balance their supply and demand by area - prices will be lower in surplus than in deficit areas. Buyers and sellers have to differentiate their bids by area, and the capacity fee is the differential between the system price (calculated as it would have been for the whole country without transmission constraints) and the area prices that emerge in the individual areas.

The connection fee: This is intended to reflect costs related to Main Grid reliability and system operation. It is levied on the basis of total demand.

The power fee: This is a residual charge, not related to capacity, levied to recover the costs of the Main Grid, which in 1995 was about half of total grid

revenue. It is levied on the basis of measured power exchange for each connection point.

Power trade with neighbouring countries are based on the transmission tariffs applicable in Norway, but adjustments have to be made to enable exchanges between the open system in Norway and the more closed systems in other countries.

- In the case of Sweden, Svenska Kraftnat has introduced new node-based transmission tariffs. In 1995, the border tariff between the two countries was the sum of the exit charge from one network and the entry charge to the other. This year, a harmonised nodal tariff has been introduced, encouraging border-free trade between the two countries.

5. The ESI Reforms in Sweden

Up to the beginning of 1996, Sweden had a set of regional monopolies in both production and distribution. Production is in the hands of 2-300 companies, 8 of which accounted for 90% of output. The transmission grid is owned and operated by Svenska Kraftnat, and distribution was divided among about 300 companies, mostly municipally owned. There were area concessions (exclusive rights and responsibilities). Sweden did not have a pool of any kind before the liberalisation and needed to do more background work than Norway.

Major producers operated a system of production optimisation, buying power from the lowest-cost producer and splitting the difference between purchase and selling prices. Long-run contracts for the largest generators' use of the HV grid have effectively limited the transmission rights of other producers and leading to vertical integration. With the reform, this situation will end and the networks will be opened up to competing sales.

The new electricity law, which came into effect on 1st January 1996, is the most important element of the reform, separating production from the networks. The reform will legally separate production and distribution from transmission and create full regulated TPA (not negotiated), under which the grid owner has to give access on reasonable terms unless he can prove that it would not be physically possible. The production and sale of electricity are open to competition (there will not be central planning of capacity expansion, rather an authorisation system like that proposed by the EU), while special permission is needed to construct or operate HV lines.

Svenska Kraftnat owns all the 220 kV and 400 kV lines and most of the interconnections with other countries. This is becoming increasingly important with market liberalisation. In principle it is obliged to provide transmission to all parties. Kraftnat is responsible for balancing production and consumption both nationally and regionally, and for the market in regulating power. It is also responsible for maintaining reliability by - for instance - setting standards for production plants and networks connected to the grid.

Production and sales will be under the normal competition authorities, while the networks will be regulated by a special network authority, NUTEK. To avoid cross subsidies, special requirements are imposed that tariffs should reflect the costs unequivocally connected with network operations in the relevant concession area. Network concessions relating to international links are subject to government approval, and all long term import and export contracts have to be reported.

The reform has been driven by the UK and Norwegian examples, and the need to keep power prices as low as possible - already they are among the lowest in Europe, reflecting Sweden's industrial development strategy.

There is a fear that small/rural consumers will not benefit from the reform, since they are subsidised in the current system. Sweden is planning to retain a franchise limit up to 1/1/99, after which all customers will be eligible to purchase power from whatever supplier they choose.

Some restrictions will remain:

- small consumers will be able to opt for regulation through supply concessions for a period of 5 years. This aims to protect those (mainly households) who face high transactions costs;

- supply concession holders will be obliged to connect/supply on a fair tariff all those in their area. If a supply company has several concession areas, it will not be able to cross subsidise between them. In the rural areas, the Social Democrats modified the system to allow some tariff levelling (with respect to grid charges - energy charges are expected to be much the same everywhere);

- small producers (eg wind and small hydro) need support to survive in the market. The supply concession holders will be obliged to buy up to 1.5 MW from them at a fixed price for the next 5 years.

5.1 The joint marketplace with Norway

One of the further features of the reform that is of most interest for the current study is the creation of a joint marketplace in electricity for both Sweden and Norway. Even before the reform in Sweden, about 10 of the actors in the existing Norwegian marketplace were Swedish, and their number is expected to increase.

Creating a joint marketplace will tend to raise prices in Norway and lower them in Sweden, to the benefit of Norwegian producers and Swedish consumers and to the detriment of Swedish producers and Norwegian consumers. These distributional consequences will be very important to the perceived success of the joint market.

A joint pool has been created, based on the Norwegian pool organisation (Statnett Marked), of which Svenska Kraftnat has bought half to form a joint pool company. The joint pool company is based in Oslo with a Stockholm office, which will initially be just an information centre but may later be able to be used for bids. Large gains from trade are expected to result from differences between the two countries such as:

i) different generation mixes;

ii) different load curves, and

iii) different energy-intensive processing industries.

The pool is voluntary, not compulsory as in the UK, and there is no central dispatch for the 2 countries.

In preparation for the joint pool, Kraftnat and Statnett have increased transmission capacity and worked to harmonise tariffs, system responsibilities and regulating markets in the two countries.

5.2 Vattenfall

A particular issue for the design of ESI reform in Sweden has been the market power of Vattenfall, which controls around half of total generation capacity and about 15% of distribution. The state as Vattenfall's owner does not want to have it split up, partly to ensure that it remains comparable in size and negotiating power to potential customers and competitors abroad, such as RWE (Germany) and EDF (France). Foreign investment in Sydkraft, the second largest company, has led to worries about loss of national control.

The market power of Vattenfall would however probably distort prices in a pool established in Sweden alone, and this was one of the major considerations in choosing a joint pool with Norway, in which it is hoped that Vattenfall's potential market power will be greatly diluted.

5.3 Transmission pricing in Sweden

Before the reform, Sweden's transmission prices were based on transmission "channels", and there will be a major changes in Sweden's transmission tariff as it switches to a node-based system similar to that in Norway, where charges are made for use of system.

In 1995 there was a border tariff charge on either side of the border, representing about 10% of the transmission costs. Border tariffs will be abolished and trade will be on a fee for transit basis. The adoption of new transmission tariffs will mean that all customers and suppliers in both Norway and Sweden are able to trade without border tariffs.

The transmission tariff has 2 elements:

- the power fee (55% of revenue) expressed in Skr per megawatt per year; this is set as a residual to recover the full costs of transmission infrastructure;

- the energy fee (45% of revenue) based on marginal losses.

If transmission bottlenecks occur, a tariff uplift will be implemented. All this is very similar in principle to the area tariffs in Norway. However, the Swedish tariff has a somewhat different design, in that the charge covering infrastructure costs is linked to the energy fee, rather than being a flat charge as in Norway. The result is that the Swedish system has much stronger locational incentives than the Norwegian one does. The Norwegian system is arguably closer to the theoretical ideal, but there is little experience in this area and the persistence of transmission bottlenecks within Norway suggests that there may be some merit in the Swedish approach.

In addition an investment fee will be levied if required by particular transmission contracts. This has not been used yet, but may be used to cover the costs of the system reinforcement required for the Sweden-Poland and Sweden-Germany interconnectors.

6. The future

6.1 Trade Prospects with Liberalisation in Sweden

Trade between the two countries could increase rapidly as the joint marketplace emerges. While the two countries are trying to reinforce their interconnectors, there are only limited possibilities, and the focus is on increasing the use of the existing capacity. Moreover, most large Swedish users have signed long term contracts to protect themselves against short term price fluctuations of the type that occurred in Norway immediately after liberalisation, and it is estimated that this accounts for as much as 80% of generation up to 1998.

It is not clear which way trade volume will move in the short term: in 1996 it is expected to be at much the same level as in 1995, but the outcome will depend on weather conditions. Nor is it necessarily the case that trade will increase over the longer term either, only that the trade which does occur will be on the basis of true comparative advantage.

In the first few weeks of 1996, unusually mild weather in both Norway and Sweden has led to a situation in which transmission bottlenecks within Norway are occurring, and a uniform price has emerged between northern Norway and Sweden, while prices in southern Norway are lower. The transmission constraint means that there are no spot sales and that there are restrictions on contract sales.

Several institutional changes are still underway. For instance, Svenska Kraftnat will not take over running Sweden's dispatch function until the beginning of March 1996, and in the interim it continues to be operated by Vattenfall with obvious conflict-of-interest implications.

Regulators are aware that there will need to be reviews, of transmission pricing issues in particular, as the joint pool develops. 1996 is seen as a trial and error period, with dialogue between the regulators and grid companies over necessary changes. A particular issue is the bidding system for transmission routes; the parties are compiling a list of other differences that need to be smoothed out.

There are for instance differences between Norway and Sweden in respect of:

1. the treatment of transmission constraints. In Norway, there are area tariffs, while in Sweden the industry has to balance by buying and selling power within a local area on a least cost basis. If Sweden needs to import power, but there is a generating constraint in the exporting area in Norway, the bottleneck fee is transferred to the nearest interconnector. Thus there are different transmission costs to be included into power prices. As a result costs may rise in Sweden without any price effect in Norway.

2. There is a separate regulation market in Norway but not in Sweden. In Sweden, producers can buy short term dispatch services, and try to optimise on the basis that those who want to expand production have their bids forwarded to the Swedish dispatcher. However, this does not lead to full optimisation.

Thus there are differences in the treatment of constraints, regulation and dispatch that prevent full optimisation. Statkraft and Svenska Statnett are aware of them and are thinking about how to achieve convergence. There will be a major review of the joint market in mid-1996 with a view to resolving remaining trade barriers.

6.2 EU issues

There is a worry over the EU debate on reciprocity - if the Swedish market is opened to Germany, they fear that trade would result in large exports and higher prices in Sweden. This has led to arguments for export limits, and a special investigator is examining legal aspects and the consistency of such limits with the Treaty of Rome.

6.3 Further enlarging the joint pool

Agreement has been reached in principle to form a joint Nordic power pool of all four Nordel countries, and the other countries are being forced to accept reform by developments in Norway and Sweden. Finland is due to open its internal market to competition in April 1996, and to join the cross-border market by 1997 (though delays may occur). Denmark poses the biggest problems, due to its very different structure and strong interconnections with continental Europe. The Norwegian/Swedish pool will be the first step towards a 300 TWh market.

A problem arising is that Danish and Finnish firms can be actors in the market, through a Swedish or Norwegian company, but are not treated favourably for border trade. Border fees will continue to apply, of about 0.4 to 0.5 p/kWh for Denmark and 1-2p for Finland.

Denmark is still vertically integrated (consumers own the network and power stations) and so is hard to include into the market. At the very least they need to separate transmission and production costs.

6.4 Trade policy issues

The joint pool raises trade policy issues that have never previously been encountered in the design of electricity trade. In particular, what is the optimal pattern of international integration? Customs union theory suggests that, once a single electricity market has formed in Sweden and Norway, the

welfare consequences of admitting further countries are ambiguous because the reduction of distortions between some players (eg the Finns, if they are admitted to the joint market) would be offset by the increased distortions between the Finns and their other trading partners.

Norway and Sweden will also need to develop a joint trade policy, and are trying to harmonise their import and export tariffs to third countries. The links to Holland and Germany are currently used mainly for exchanges, and it will be important to put such harmonised tariffs in place for long term exports to become feasible.

According to NUTEK (Swedish Electricity Market 1995, p15), the Swedish government thinks there is no need for increased control on international electricity trade in the short term, but that "opportunities should be available for placing certain restrictions on foreign trade .. if the reliability of supply should be threatened in the future". It therefore recommends:

- a special concession regime for imports and exports; and
- extending the obligation to notify long-term contracts

while recognising that trade must be regulated - if at all - in such a way as not to jeopardise its beneficial effects. A special investigator has been appointed to draw up proposals for new legislation in accordance with these principles.

Regional Grid Networks 2

Case Study 3 : Electricity Trade in Europe

Electricity Trade in Europe

Table of Contents

Electricity Trade in Europe

1. Introduction

This case study examines two principal aspects of electricity trade in Europe:

1. trade under the UCPTE system of co-ordination and support agreements between European utilities; and

2. the impact of European Union rules on transit, third party access and unbundling as the European Commission attempts to legislate a competitive internal energy market within the EU.

Section 2 describes the UCPTE, looking at the trade within the system, the structure of the electricity industries in member countries, the rules under which UCPTE operates, power prices and international trade contracts between selected members. It focuses on the interaction between market structure and electricity trade.

Section 3 looks at EU rules. Most of the UCPTE's main members are located in countries that are member states of the European Union (the exceptions being the states of the former Yugoslavia and Switzerland), and are thus subject to the rules that the EU issues to govern the development of the internal energy market. The most important of these rules are the Transit Directive and the forthcoming regulations relating to third party access to energy networks in member states.

Section 4 looks at the main lessons from the case study.

2. The UCPTE System

2.1 Background

-The UCPTE is the Union for the Co-ordination of Production and Transmission of Electricity, and is an international electricity industry association whose members are chosen from representatives of the generation and distribution companies in its member countries. It was founded in 1951, and its current member countries are: Belgium, Germany, Spain, France, Greece, Italy, Slovenia, Croatia, Bosnia-Herzegovina, other regions of former Yugoslavia, Luxembourg, the Netherlands, Austria, Portugal and Switzerland. Since 18 October 1995 the systems of Poland, Hungary, the Czech Republic and Slovakia have been synchronised with UCPTE.

2.2 Trade within UCPTE

As Table 1 shows, the volume of trade within UCPTE and between UCPTE and third countries is very large. During 1994 imports were 8.8% of total UCPTE production, while exports were 9.5% of total production. Exchanges of electricity have grown rapidly, and since 1975 total exchanges as a share of consumption have increased from 6% to over 10%.

The UCPTE experience is interesting for a study of the necessary conditions for regional electricity trade for a number of reasons, but principally because the majority of its member countries' electricity supply industries are owned and operated by vertically integrated utilities. It is therefore sometimes suggested that the fact that this has been consistent with large scale trade occurring provides to be a counter-example to the argument that unbundling is required for efficient electricity trade.

Initially, trade was mainly for reserve support and to enhance reliability. More recently, there has been a good deal of trade growth within UCPTE, involving long term contracts. It is by no means clear that this trade is efficient, particularly from a long-run point of view. In our view, trade within UCPTE has largely been driven by non-economic considerations, which have led Europe to develop complementary patterns of excess capacity in some countries and capacity constraints in others.

Table 1 : Exchanges of Electricity (UCPTE and third countries), 1994

	Net Electricity Imports (TWh)	Imports/ Production (%)	Exports/ Production (%)
Austria	-1.0	20.2	22.5
Belgium	3.9	13.0	7.4
France	-62.2	0.7	14.6
Germany	3.0	8.1	7.3
Greece	0.3	2.2	1.5
Italy	37.6	17.6	0.5
Luxembourg	4.3	418.2	48.7
Netherlands	10.8	26.3	8.3
Portugal	0.8	8.1	5.1
Serbia	0.1	0.8	0.5
Slovenia/ Croatia	1.8	13.8	4.2
Spain	1.9	3.5	2.2
Switzerland	-11.6	23.7	41.9
Third countries[1]	-10.4		
Total	**0.0**	**8.8**	**9.5**

[1]: *Albania, Andorra, Bulgaria, Czech Republic, Denmark, East Germany, Great Britain, Hungary, Romania, Slovakia and Sweden.*

France is by far the largest exporter of power within UCPTE, accounting for 43% of total gross exports (see Figure 2). It is even more important in terms of net exports, being the only important net exporter in the entire UCPTE system (see Table 1). These exports chiefly reflect the French government's determination to achieve self-sufficiency in electricity production through the development of nuclear power in the 1970s and 80s, and more recently its decision to continue with nuclear power plant construction ahead of the growth of domestic demand, in order to maintain its nuclear construction industry. This policy has left France with a large amount of excess capacity with low short run marginal production costs.

Figure 1: UCPTE Countries' Power Imports

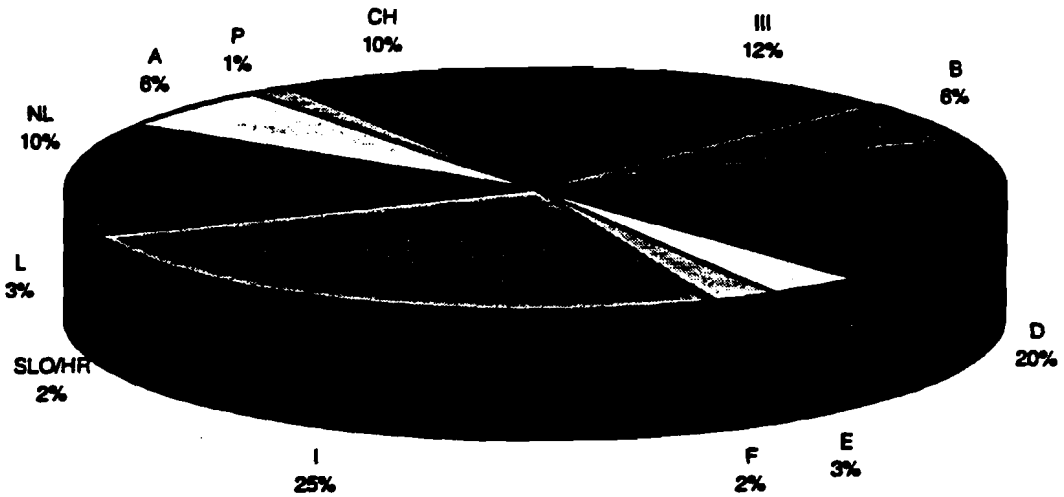
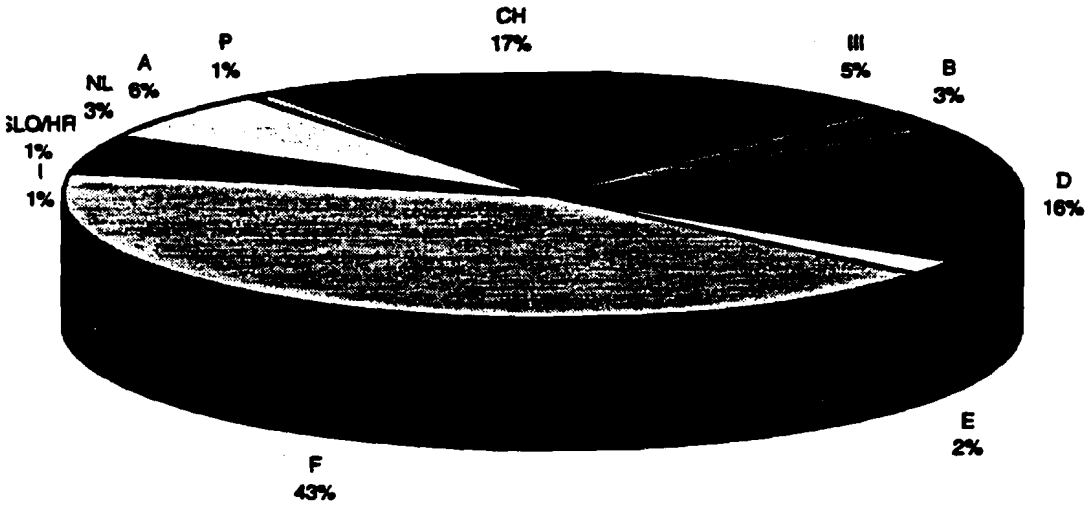


Figure 2: UCPTE Countries' Power Exports



Key:

A	Austria	F	France
B	Belgium	III	Non-UCPTE countries
CH	Switzerland	L	Luxembourg
D	Germany	NL	Netherlands
E	Spain	P	Portugal
Slo/HR	Slovenia/Croatia		

The policy has arguably been economically rational for France, given:

- its lack of indigenous energy resources; and
- the value of maintaining its nuclear construction industry as a centre of excellence.

However, it is very unlikely that a private, profit-motivated supplier would have made the same capacity decisions. EDF's financial position, without government guarantees on the very large debts it incurred to finance its highly capital-intensive investment strategy, would have been untenable.

The major gross importers within UCPTE (Figure 1) have been:

- Germany, where electricity has traditionally been high price due to heavy taxation. However, Germany is also an important exporter of power and its net position is almost in balance;
- Switzerland, which plays a key role in European electrical interchanges, both because of its position and because of the role its hydro resources (including pumped storage) play in optimising production in a number of countries, and where there are severe constraints on developing new capacity;
- Italy where lack of domestic energy resources and reliance on Algerian and Russian natural gas has led to a considerable interest in diversification of energy supplies, and where the rejection at referendum of proposals to build nuclear generating capacity (combined with the decision to leave CCGT development to the private sector) has severely constrained capacity. ENEL also sees imports from France as a highly cost-effective way of meeting demand.

UCPTE countries export large amounts of power to non-member countries, the most important being France's exports to the UK. These amounted to 16.9 TWh in 1994, considerably exceeding total net exports from the UCPTE region, and were partly offset by imports from Denmark (2.7 TWh) and the Czech Republic (3.0 TWh).

Table 1 shows details of UCPTE electricity exchanges in 1994, and Figures 1 and 2 show the relative shares of each UCPTE country in exports and imports of power, including trade with non-member countries.

2.3 Structure of UCPTE electricity industries

Only in the Netherlands, Spain and Portugal, of the UCPTE countries, is the ESI to any degree liberalised or market based. Vertical integration remains common, and France and Italy provide instances of nearly-complete vertically-integrated monopolies. This section briefly describes the main structural features of the component industries in the member countries (Greece, the former Yugoslav republics and Luxembourg have been omitted for simplicity).

1. Austria - the ESI is dominated by the Verbundgesellschaft, which controls around half of generation, owns the HV grid and holds a monopoly on imports and exports. In addition, nine regional and five municipal utilities hold exclusive distribution rights in their franchise areas and generate part of their own supply. Plant construction is determined by the Verbundgesellschaft, which also sets the wholesale electricity tariff. The state owns a majority stake in the Verbundgesellschaft, though 49% of the shares have now been sold for financial reasons;

2. Belgium - the ESI is dominated by the privately owned Electrabel, which accounts for over 90% of electricity production, controls the transmission grid and supplies half of final sales. Prices are uniform and are set by a statutory committee;

3. France - EdF has a near-complete monopoly of generation (90% of capacity), owns the entire HV grid, has a legal monopoly of exports and imports. It also operates (jointly with Gaz de France) an unbundled distribution enterprise responsible for 97% of retail electricity sales. Tariffs and capital expenditure are regulated by the Ministry of Finance, while government also sets a Contrat de Plan setting out performance targets for EdF;

4. Germany - the industry has a very complex structure with over 1000 utilities, but is dominated by 8 interconnected vertically integrated firms which together account for 2/3 of generation in the former West Germany, and dominate generation and transmission in the East. They also account for about 1/3 of final sales, and have a mix of public and private ownership. There are demarcation agreements between generators and distributors that map out each utility's supply area, and concession contracts give each utility an exclusive right to supply in return for a payment to the municipality, an arrangement that is so far exempt from the country's Anti-Cartel Law;

5. Italy - the state-owned ENEL controls the industry. It is a vertically integrated utility, responsible for over 80% of production, and holding a monopoly on imports and exports, transmission and distribution (apart from areas controlled by municipal authorities such as Milan, Turin and Rome). Responsibility for tariffs and construction is vested in an inter-Ministerial committee;

6. Netherlands - production, transmission and distribution are separated. Four regional companies control generation (including plant construction), and the transmission company (SEP) is obliged to purchase their surplus output. It dispatches generators in cost-based merit order and operates a pooling system setting a uniform National Bulk Tariff in which generators buy power to serve the distributors. It also has a monopoly (in practice) over imports and exports and fuel purchases. Distributors, mainly owned by municipal and provincial governments, have a franchise on customers below 20 GWh per year;

7. Portugal - the state-owned EdP, controlling 94% of generation, was unbundled in 1994. There are now a state-owned generating company, two large private generators and small hydro plant owned by distributors: these are responsible for supplying the public system (SEP). The grid is owned and operated by the state-owned REN, and buys power through binding power purchase agreements with the generators. There are four regional distributors, subject to a uniform national tariff. Alongside the SEP is the independent SEI, where producers can supply clients directly, or gain access to the grid to supply them through REN. So far, renewables and CHP are the main generators included in the SEI: the choice of whether new plant will be in the SEP or the SEI will be made case by case. Further details of the Portuguese reform are given in Section 3.3.1;

8. Spain - four major utilities and 16 smaller companies together produce and distribute almost all of Spain's electricity. Each distribution company has a delineated service area, and there is no competition between them. Transmission and dispatch are in the hands of the state-owned REE, which holds a de facto monopoly on imports and exports. Under 1995 reforms, the construction of new plant has been opened up to tender, an Independent System has been created in which generators can supply clients directly and import/export electricity, and generation and distribution accounts have to be unbundled. It is not clear whether fuel type will be set prior to tendering, but no capacity additions are expected to be necessary until after 2000. Accounting separation is being enforced between

generation and distribution. Legal unbundling will be required in 2000, though there is increasing pressure increasing for the changes to be limited to accounting separation only. Further details of the Spanish reform are given in Section 3.3.1.

9. Switzerland - there are about 1200 electricity organisations, which are highly decentralised, and many generate and distribute their own power. Most of the generation and transmission belong to six inter-regional companies, which are involved in all levels of the industry, the 3 largest communal organisations, and Swiss Railways which generates and transmits most of its own power. Most large projects are built as joint ventures between several organisations. The inter-regional utilities trade with each other and with foreign utilities to manage their hydro resources. The major international traders however are two private companies (Atel and EGL), which also supply distributors on long term contracts. The Federal government has a very limited role, apart from nuclear power station authorisations. There are serious environmental objections to constructing more transmission lines or generating stations.

Given the lack of competitive markets on both sides of the trading relationship in the majority of UCPTE trade, the fact that trade is taking place does not guarantee that trade is economically advantageous from a long-term perspective.

However, the pattern of widespread restrictions on further nuclear power stations (for instance in Austria, Italy and Spain) and active promotion of nuclear capacity in France has led to a situation which establishes a form of "comparative advantage" among the member countries in power production. It is very likely that, without restrictions and promotion, generation expansion in Europe would be based on much the same technologies as in the liberalised market in the UK, ie on combined cycle gas turbines. This could lead to a situation with <u>less</u> trade in electricity than is currently observed, though potentially with much more trade in gas, which is cheaper than electricity to transport in large quantities and over long distances.

2.4 Operation of UCPTE

The UCPTE is, in effect, a club which lays down the technical specifications governing electricity trade between its members and arbitrates in disputes between them. The individual members collaborate voluntarily and each remains solely responsible for supplying its own customers. There is no pool, and trade takes the form of bilateral exchanges under contractual relationships. A spot market for short-term exchanges of power also

operates, but this too is based on agreements between utilities rather than a pool.

For mutual grid control support the UCPTE members provide each other with appropriate information on the basis of bilateral agreements. Once a year, data on the whole UCPTE interconnected system is made available to all system partners for use in transmission system planning and control.

- UCPTE members agree to provide their mutual support to exchanges subject to technical and operational feasibility and maintaining security of supply to the utility's own customers. Remuneration for this support is agreed on the basis of guidelines laid down by UCPTE, but subject to negotiations on the exact sums payable.

The short-term power market with unsecured energy supplies (the spot market) is the result of the implicit comparison of marginal costs of generation. Information on availability, kWh prices and delivery conditions is made available through an UCPTE-organised e-mail system to all interconnected partners to assist grid control centres in arranging transactions[1].

2.5 Prices in UCPTE countries

Industrial electricity prices in the main UCPTE countries provide an indicator of the level of bulk supply prices. They are to some extent as one would expect in the light of the trade pattern. Power prices are relatively low in France, the main exporting country, and relatively high in Italy, which is a large importer and Spain where imports are increasing.

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[1] At present the following UCPTE members are connected to the e-mail system:

Austria - OVG

Belgium - CPTE

Switzerland - BKW, EGL, EOS, NOK

Germany - BAG, BW, EVS, HEW, PE, RWE, VEAG, VEW

Spain - REE

France - EdF

Italy - ENEL

Portugal - EdP

Netherlands - SEP

Table 2 : Industrial electricity prices in selected UCPTE countries, January 1994 (ECU/00kWh, excluding tax)

	10 GWh/yr	70 GWh/yr
Belgium	6.9	4.2
France	6.5	4.6
Germany	10.0	7.2
Italy	8.4	5.0
Netherlands	6.2	4.3
Portugal	8.5	6.0
Spain	7.2	5.8

Source: Eurostat "Electricity Prices 1990-94", Brussels 1994, page 190

However, price differences clearly persist, despite the extent of the electricity trade that is occurring. It is therefore appears that trade is not exhausting all the opportunities that would currently be economic.

Furthermore, there are some reversals, where price differentials are contrary to the flow of power. Prices for instance are lowest in the Netherlands, as would be expected from its competitive industry structure and comparative advantage, while the country remains a major net importer from France. A similar, though less marked, situation occurs with Belgium. Germany, while having the highest prices, is only a modest net importer.

2.6 International trade contracts

This section examines in more detail the contractual basis of trade between some UCPTE members. Because of the recent liberalisation of the internal markets in the Iberian countries, it focuses on trade between France, Spain and Portugal. Limited information was also gathered on the situation in Austria.

2.6.1 France, Spain and Portugal

Under the impact of the bilateral agreements with EdF and a tripartite agreement with EdF and REN, Spain changed from being a net power exporter in 1990-91 to a net importer in 1992-4.

Table 3 : Spain's Net Imports of Power, 1990-94 (GWh)

	France	Portugal	Andorra	Total
1990	-364	-37	-19	-420
1991	-536	-92	-49	-677
1992	2,011	-1,341	-29	641
1993	1,585	-175	-143	1,267
1994	2,846	-887	-109	1,850

Spain's trade with France is based on system complementarity. EdF has a large base load capacity (nuclear), while Spain by contrast has adequate capacity both regulatory (hydro) and peak (oil/gas) but projects a shortage of base load capacity. However, trade is restricted by the limited capacity of the interconnectors over the Pyrenees, and efforts to expand these interconnectors are facing heavy environmental opposition.

Spain's National Energy Plan identified imports from France as one of the cheapest options for expanding baseload supplies. But the actual contract price is relatively expensive (6 US cents/kWh). It has increased over the last 5 years due to exchange rate changes, as the Franc has appreciated by 25%. Currently, natural gas and coal plants in Spain can produce baseload power below the import contract price, at about 4 US cents/kWh.

Spain's Ministry of Industry supports large degree of national independence in energy supplies, but the authorities do not stipulate the level of international trade.

2.6.1.1 Bilateral trade between Spain and France

A long-term energy import contract, valid until 2009, was initiated between REE and EdF in October 1994 over a 400 MW interconnector. This contract was agreed following a moratorium on nuclear plant construction in Spain at a time when it appeared that future demand would outstrip supply. Since its agreement the growth of electricity consumption in Spain has slowed, and it is questionable whether the electricity delivered through this contract is available at a lower economic cost than that already provided in Spain.

There are 2 relevant international trade contracts:

1. The main contract, of 16 years duration, under which France exports base load to Spain.

Table 4 : Capacity in the main EdF/REE contract (MW)

1994/95	300
1995/96	500
1996/97	600
1997/2004	1000
2004/5	500
2005/10	300

Capacity under the contract is programmed to build up in parallel with expected interconnector capacity and declines towards the end of the contract period. Its availability is 8760 hrs/yr, and the contract is denominated in Pesetas.

2. A backup contract under which Spain exports peak and regulating power to France. This contract started on 1/11/95 and runs for 15 years.

Table 5 : Capacity under the EdF/REE backup contract (MW)

1995/96	500
1996/97	600
1997/2005	1000
2005/10	300

Total use is limited to 4890 hours, and to 600 hours/year. The contract is only effective in the winter period (from 1/11 to 31/3), and is bound to the main supply contract.

Payment is in 3 parts:

i) Power - an annual payment for investment, denominated in a mix of Francs and Pesetas;

ii) Supply - a monthly payment for O&M, in Francs; and

iii) Energy - a payment per kWh, in Francs

2.6.1.2 Trilateral trade

In July 1994 a tripartite agreement between REN of Portugal, REE of Spain and EdF was initiated, which provided for partial implementation of a previous agreement. Under these arrangements EdF provided guaranteed capacity of 300 MW between July and September 1994, and 150 MW thereafter until September 30 1995. Exchanges were then suspended until a new interconnector is powered up, when service will be resumed until 1999. The tripartite contract with France and Portugal has thus lapsed, and only short term trades are taking place.

The contract, which ran in principle for 5 years, was a very complex arrangement. Under its provisions, capacity was provided by EdF to REE (385 MW) and by REE to REN (301 MW). The latter amount depended on the trade from EdF to REE. No financial payment to REE was involved. The contract allowed load shedding of up to 200 hours/year.

Full contract capacity was available from 1/7/94 - 30/9/94, and half of contract capacity from 1/10/94-30/9/95.

Underlying this arrangement was a Portuguese/French payment for power; REE received only power, in principle to compensate it for transmission losses and implicit Use of Service charges. In fact, carrying power for Portugal reduced REE's system costs because the flow under the contract was against the internal power flows in Spain. Within Spain, the main supply area is in the Northwest, while the main demand is in the Northeast.

The future trend in Spain is for REE to be paid in cash for transmission services, though it is difficult to separate the wires business from payment for ancillary services. The use of standard costs for regulating transmission in Spain however means that REE will only recover its investment costs in transmission and wheeling.

2.6.1.3 Other Spanish trade

REE has an export agreement with Morocco's ONE, over a subsea interconnector that was expected to be in operation by 1996, but now likely to be delayed to 1997 or 98. It is a 3 year baseload contract with interruption clauses, and is designed to take advantages of excess capacity in Spain.

It has the following features:

Capacity	300 MW
Load shedding	600 hours/year
Energy	2,448 GWh/year

This contract is much more important for Morocco (where it represents 20% of capacity) than for Spain.

2.6.2 Austria's international electricity trade

Austria's international electricity trade is all undertaken by the Verbundgesellschaft, except for the provincial utilities in Tirol and Voralberg, whose imports and exports with Switzerland and Germany, based on pumped storage, are clearly least-cost and are regarded as traditional exchanges. Since Austria's system is 75% hydro-based (mainly run of river), it is complementary with other systems and could benefit substantially from trade.

The OMV company, the provincial utility of Lower Austria, has some exports to the Czech Republic, in collaboration with the Verbundgesellschaft's transmission department (for which no government approval is required). Access to these lines is by contract only, and is only available to electricity sector enterprises and a few traditional eligible customers. OMV could enter into direct import contracts, but has to take a fixed percentage of power from Verbundgesellschaft before doing so.

Austria has been a net exporter of power, and this was a government target in setting the generation expansion programme. There was also an idea at one time (now discontinued) to develop Austria as an electricity trading centre for Europe, and import contracts were negotiated by the Verbundgesellschaft from Noj Maroj hydro in Hungary and Slovakia for 20 years and for 1.2 bn kWh/year. The idea had been to onsell power elsewhere in Eastern Europe, but demand there has fallen further than expected. This also partly reflected the increasing difficulty of new power station construction in Austria, which has largely been stopped by "green" lobbies.

The Verbund's management has since renegotiated with the Hungarian grid company, since prices had been based on an RPI index at a 1986 base, which meant that imports became very expensive.

3. The European Union

3.1 Transit Directive

The Council Directive on the transit of electricity through transmission grids was approved on 29 October, 1990 and was supposed to come into force on 1 July, 1991. In fact, however, full implementation did not occur until 1994. The method of implementation differs between countries with some issuing decrees obliging system operators to comply with the Directive, some amending license conditions appropriately and some agreeing contracts or conventions with the system operator.

The aims of the Directive were to promote electricity trade by making it obligatory for grid operators to allow the transit of electricity through their networks, and to monitor compliance with this. The Directive applies to contracts of over one year's duration for electricity trade beginning and ending in an EU member state, and which crosses at least one intra-EU border during the course of transmission.

There are some doubts about the effectiveness of the Directive. European utilities report that it is often relatively easy to circumvent, by:

1. setting contract lengths at less than one year (for instance Franco-Belgian trade escapes regulation in this way); or

2. routing contract paths through Switzerland (which is not an EU member) so that transmission from Germany to Italy for instance need not cross an intra-EU border.

Even where the formal conditions would require that the Directive be applied, for instance in the tripartite trade between France, Spain and Portugal, the utilities involved argued that the contract was exempt as it was not a wheeling contract in the sense of the Directive. Thus the market power of network operators may not be greatly restricted by the Directive - they may exercise it by making their trading partners agree to contract conditions that make the directive ineffective in monitoring prices and other access terms.

The Directive requires utilities to notify the European Commission and the relevant national authorities of all negotiations for the transit of electricity which fall under the directive's provisions; and to inform them of the reasons for failure to conclude these negotiations within 12 months, if relevant. The European Commission is empowered to intervene to enforce the obligation to provide transit for electricity if it considers the reasons given for the failure of negotiations are insufficient.

3.2 The Internal Energy Market

3.2.1 The state of the debate

The European Commission has been seeking agreement on measures to introduce a competitive internal energy market within the EU since 1992. There has been intense opposition from most EU utilities, led by EdF and the German utilities, although for different reasons:

1. The French government and EdF have been concerned to retain their traditional emphasis on security of supply, and fear that a competitive electricity market would lead to the end of French self-sufficiency in generation;

2. The German utilities are concerned that a competitive market will open up their markets to massive imports of cheap French power whilst they themselves remain handicapped by heavy taxation.

Support for the internal energy market has been led by the UK, and latterly has received some support from the Iberian peninsula and Scandinavian countries.

The preferred option of the Commission was initially (in 1992) for thorough liberalisation, including:

1. compulsory unbundling of utilities;

2. compulsory or regulated third-party access (TPA) to transmission and distribution networks; and

3. the freedom for large customers to purchase power from any generator within the EU.

This stance has been softened by the intense opposition encountered from a number of countries with vertically integrated companies. It was further weakened by the French alternative policy proposal of a single buyer model (SBM) during 1994. Under this proposal, electricity might be purchased from abroad by large customers, but the transaction would be routed through a country's national utility. In response, during 1995 the EU developed proposals for "negotiated" third party access, under which producers and consumers would have to negotiate with the transmission company under mutually agreed wheeling charges.

At the Council of Ministers meeting on the issue in June 1995 three options were outlined:

1. the SBM;
2. a version of negotiated TPA with a tendering process for new capacity; and
3. negotiated TPA with a licensing process for new capacity.

Under the Spanish presidency (July-December 1995), the EU sought ways to reconcile these options, and the general feeling seems to be that member states will be given a choice of the systems. Intense arguments can be expected over the definition of "major customers", and in particular whether or not they should include distributors. A meeting scheduled to take place in December 1995 to decide the issue was postponed due to the inability of the national authorities to agree on a common position.

3.2.2 The proposals

3.2.2.1 Negotiated TPA

This system is based on opening up each country's transmission and distribution networks to third parties. Access to the networks can, theoretically, only be refused for technical or capacity reasons, but the details of such access will be open to negotiation. Major customers would be able to buy power from any generator within the country or the EU and negotiate to transmit it through EU systems to their location.

New capacity would be based on either:

1. an authorisation regime (the Commission's original preference); or
2. a tendering regime (an attempt to reach a compromise).

In the authorisation regime, the initiative on new capacity lies with the generators, and all new and existing plant is opened up to competition. In the tendering regime the regulatory authority would determine new capacity requirements and call for tenders to provide them. This system will permit the regulatory authority to give preference to certain fuel types for reasons of security of supply or similar.

3.2.2.2 The Single Buyer Model

The SBM aims to introduce competition into generation while preserving public service obligations and long-term system planning. A single buyer would:

1. operate the transmission network and purchase power from generators within and outside the country to sell on to distributors and major customers;

2. have an obligation placed on it to purchase all power produced within its system and imported by eligible customers; and

3. despatch generating plant in economic merit order.

Major customers would be given a right to purchase power from generators outside the country but they would have to wheel this power through the network of the single buyer, selling the power to the single buyer at the border and purchasing it back at the required site for the selling price plus a mark-up to cover the costs of transmission. This right would not extend to purchases made from generators located within the system of the single buyer. Transparency in prices would be assured by the publication of transmission charges.

New capacity would be constructed through a tendering process, although autoproducers, renewable energy and CHP might operate under a parallel authorisation procedure.

3.3 Predicted effects

In a recent study for the EU[2], London Economics has estimated the likely impact of the TPA proposals on the level of intra-European electricity trade, over the period up to the year 2020. Taking the EU as a whole (rather than the UCPTE), current electricity imports are approximately 6% of total demand. In the absence of reforms to increase competition, this would be expected to decline gradually, principally because the increasingly widespread adoption of the latest gas-fired generation technologies in many countries leads to gradual cost convergence.

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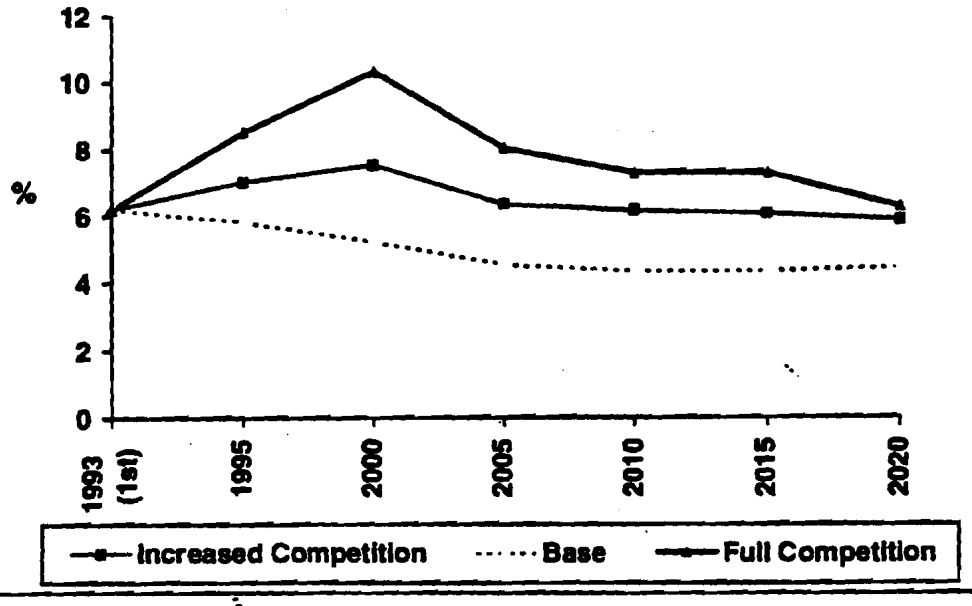
[2] Completion of the Internal Energy Market, Interim Report to the European Commission, December 1995

Figure 3: Share of Imports in Total Demand



With the full competition that would accompany TPA, by contrast, it is predicted that the share of imports would rise fairly rapidly to about 10% of total demand within the next decade. Thereafter the import share would begin to decline again as costs are harmonised across countries, reaching about its starting level in 2020 but remaining above the level that would prevail in the absence of liberalisation. Much of the increase would reflect greater exports from France to the Benelux and Iberian countries.

Since the trade occurring under a more liberalised regime is economically beneficial by definition, it follows that failure to liberalise would entail welfare losses. Given the scale of the trade reduction, and the large welfare gains apparent for instance in US pools from even low levels of trade between utilities, the welfare effects could be very significant.

It is difficult to model the impact of the single buyer model convincingly, and it is represented in the model as an increase in competition, but not to the full extent that would result from TPA.

3.3.1 Recent developments

This section reports recent developments in selected countries in response to the reform proposals put forward by the EU Commission.

Austria

The regional distributors have put forward proposals to take-over and break-up the Verbund, retaining it as a generator but unbundling its transmission and plant construction roles. The Verbund has argued for an extension of existing co-operative agreements, and for itself to take over the role of central control of generation.

Since 1993, there has been discussion of moving from state to "social partnership" regulation, and this will probably happen at the beginning of 1996. Under this system, the Ministry of Economic Affairs will leave monitoring to the Chambers of Industry, Agriculture and Labour, which operate at both a Federal and province level.

The tariff calculations use cost-based limits. For instance it has been decided that the cost of equity will be set by the market, and is currently about 7%. Labour costs are standardised, to avoid undue salary increases. The Chambers are also suspicious about overstaffing, and OMV has adopted a staff reduction target over 5 years. The MOE will remain the owner of the Verbund (51%).

Austria is not discussing unbundling of other enterprises. Many electricity sector companies are vertically integrated, and the Municipal companies are horizontally integrated also (providing gas, water, heat and transport services in their areas). They are lobbying not to be split up, though there will be accounting separation.

Customers such as paper mills are pressing for more competition (there is limited competition from cogeneration plants). The Verbund favours the SBM, while the Provincial Companies are more in favour of TPA. There is some discussion of having ten "single buyers", including all of the Provincial Companies.

France

The French government opposes TPA i) because of fears that downstream consumers will suffer - if large clients get the right to buy from other producers this will impose extra costs on franchise consumers - and ii) because investment in the nuclear programme would not have happened without a captive market. Gas would be the economic alternative, but France wants to keep control of energy supplies in case of a future oil shock; this is a long-term versus short-term issue.

France expects that there will be a compromise allowing utilities to control their own networks with UCPTE as the co-ordinator. They hope that states will be able to choose between the SB and TPA models. EDF accepts the need for separate cost accounting for the different levels of the ESI, but not for separate management.

Italy

Plans were announced in December 1995 for the three stage privatisation of ENEL with a tranche of shares being sold at each stage. In the first phase ENEL will have accounting separation but will remain vertically-integrated. In the second its generating activities will be split off into a separate company under ENEL's ownership, while transmission will remain an ENEL monopoly (apart from the 2000 km of lines owned by Edison) and distribution will be reorganised in collaboration with the major local authorities. The Italian Government will retain a golden share until the third phase.

An act laying the legal basis for an Italian regulator was passed in November, 1995. At present though, the membership of any regulator is a subject of debate, with most potential candidates being tarnished by their links with corruption.

Netherlands

A September, 1994 report proposed opening up the ESI to full competition. Contracts would be agreed between generators and distributors. These contacts would be organised through an independent power procurer which would link supply and demand. Consumers would also be given full access to the public network to purchase power from any supplier. Utilities would be unbundled.

Recent leaks suggest the Dutch Government is considering a similar reform with the addition of the devolution of capacity planning to generators and distributors on the basis of agreed contractual obligations.

Portugal

EdP was unbundled in September, 1994 and implementation of a new framework for the ESI began in April, 1995. The ESI is now divided into a public or "binding" system (SEP) and an independent or non-binding system (SEI). The transmission system is operated by REN which purchases power from CPPE and other generators at varying tariffs and sells on to four regional distributors at a uniform national tariff. REN's transmission tariff is controlled by a holding company on the basis of historic asset values, and it is not intended to profit from its energy trading activities. The transmission tariff is uniform, not differentiated by line or distance.

In the SEP the generating arm of EdP, CPPE, is responsible for supply through binding power purchase agreements. REN is the single buyer within the binding system, and controls all supplies including imports. The generation in this system includes large new investments in coal fired (Pego) and CCGT generation by outside investors such as the UK's National Power and Powergen.

Alongside this system, in the SEI, major customers and the distributors (for up to 8% of their requirements) can purchase power directly from generators. Independent power producers can use the network to supply whoever they wish. If required, this power can be transmitted through REN under non-binding TPA agreements. REN is responsible for tendering for new capacity.

A regulatory agency will eventually be established to approve tariffs and contracts.

Spain

A new electricity law deregulating the ESI came into effect on 20 January, 1995 and is being gradually implemented by decree. It requires the unbundling of utilities and sets up an independent system operating in similarly to Portugal's. Construction of new capacity is opened up to tender.

The new Law established an Integrated System, where new plant is to be built under an open tendering process, accounting separation is required between generation and distribution, and imports under long term contract are open to any generator. In the Independent System, any group can install capacity without limit, and can seek customers either through the national grid (REE, which is obliged to give access) or through its own lines. However, REE is not obliged to buy or sell this power.

The Independent System in principle meets the EU's TPA requirements (though the formula regulating TPA in Spain has not yet been set), while the Integrated System had to be maintained because of the interest of private investors in generation and distribution (a constraint that did not occur in the UK, for instance).

4. Conclusions

The main conclusions from this case study are:

1. that the fact that large-scale electricity trade is occurring in Europe is no guarantee that the full economic benefits of trade are being realised under the current regime;

2. that the amount of electricity trade would increase substantially if the market were liberalised and third party access introduced;

3. that the vertical integration of many utilities within Europe is an obstacle, both to the realisation of gains from trade and to attempts to implement the more liberal access regimes that would be required to realise them;

4. that as a result of vertical integration, transmission arrangements within and across countries are still an obstacle; and

5. that even when access issues are resolved, transmission pricing will remain an issue that needs to be addressed.

Regional Grid Networks 2

Case Study 4 : Electricity Trade in South America

(Chile, Argentina and Uruguay)

Electricity Trade in South America

(Chile, Argentina and Uruguay)

Table of Contents

1. Introduction

This South American case study, which focuses on Chile, Argentina and Uruguay, is particularly interesting for two reasons. First, the process of dramatic reform of power utilities began with the 1982 reforms in Chile, and the Chilean model has subsequently been introduced (with some modifications) in Argentina, Peru and Bolivia. Second, both Chile and Argentina introduced innovative transmission pricing systems, which in Argentina's case may be an obstacle for the further development of electricity trade with Uruguay and other countries.

Although electricity trade is presently very limited in this region (a 500 kV AC interconnector between Argentina and Uruguay at Salto Grande - a 1900 MW jointly owned hydropower station which was commissioned in 1978), there is great potential for the development of trade. To date co-operation in the electricity supply industry (ESI) has focused on jointly-owned hydro power plants. In addition to the Salto Grande plant, there are jointly owned plants in Paraguay - Argentina (Itaipu) and in Argentina - Paraguay (Yacyreta). Further, cross ownership and joint ventures of both generation and distribution companies has become more common following the reforms of the ESIs in Chile, Argentina and Peru. Thus Chilean companies own two power plants in Argentina and one in Peru.

The case study is in three parts. The first briefly summaries the restructuring of the ESI in Chile and Argentina, and reviews proposed changes in Uruguay. The second examines the transmission pricing systems in Chile and Argentina (UTE in Uruguay does not have a transmission tariff), and identifies the pricing issues which may inhibit the development of electricity trade. The third briefly reviews the prospects for the further development of electricity trade in the region, including that with Brazil and Paraguay.

2. Restructuring

2.1 Chile

The reform of the Chilean ESI aimed to improve the industry's efficiency and assign a subsidiary role to the State. This was to be done by decentralising the ESI, increasing competition and through privatisation. Following reform, the industry has moved towards private ownership, particularly in generation. This is shown clearly in Table 1, which shows the key players and ownership of the ESI in 1995.

The operations of the industry, including the energy trading pool, are overseen and co-ordinated by the industry regulator, the National Energy Commission (Comision Nacional de Energia).

The reforms were introduced through the 1982 Law of Electrical Services. This is a very detailed law. It contains many of the detailed rules for the operation and development of the ESI which are usually in the licences given to the various players in the industry[1]. One consequence of this is that it has been difficult for the Chilean ESI to adapt to changing circumstances. Other countries in the region, including Argentina and Uruguay, have learned from this experience and either have or propose to have much more general enabling legislation.

2.2 Argentina

Argentina's power sector was in crisis in the late 1980s. Plant availability factors were as low as 10%, quality and reliability of supply were low, and prices were too high. The government decided on a major restructuring of the ESI and change of ownership. It chose to build on the Chilean model, with the vertical and horizontal unbundling of the industry and the introduction of a wholesale electricity market (pool). However, learning from Chile's experience, the government decided to make the reforms through a very general electricity law. This would facilitate making the later changes to the ESI which would be required as the reformed industry evolved.

[1] The law does not cover payments for ancillary services, which has caused some problems.

Table 1: Ownership and activity in the Chilean ESI (1993 data)

Company	Function	Ownership	Size
Endesa	Generator	Private (main shareholder = Enersis)	1929MW (1603 hydro, 326 thermal)
Chilgener	Generator	Private (main shareholder = none)	757MW (245 hydro, 512 thermal)
Pehuenche	Generator	Private (main shareholder = Enersis)	500MW (500 hydro)
Colbun	Generator	Government 93%	490MW (490 hydro)
Pullinque, Pillmaiquen, Guardia Vieja, Florida, Carbomet, Aconcagua	Generators	Private	161MW (156 hydro, 5 thermal)
Autoproducers	Generators	Private	368MW (83 hydro, 285 thermal)
Transelec	Transmission	Private (owned by Endesa)	
Chilectra Metropolitana	Distribution + some transmission	Private (main shareholder = Enersis)	1,000,000 customers approx.
Chilectra Metropolitana	Distribution + some transmission	Private (main shareholder = Enersis)	1,000,000 customers approx.
Chilquinta	Distribution + some transmission	Private (main shareholder = ?)	300,000 customers approx.

The pool was established in 1991, with the plants still in public ownership. The wholesale market consists of two sub-markets, a spot market and a term market. The spot market accounts for about 35% of energy and the term market for 65%. The latter market comprises generators and distributors with different length contracts. The distribution companies were privatised with eight year contracts, but new contracts are typically for one or two years.

The privatisation programme began in 1992, with the privatisation of two thermal plants, one of which (Costamera) was bought by ENDESA of Chile. In order to ensure that privatisation would be successful, these thermal plants were given eight year contracts (at what turned out to be high prices) with ENDENOR, the privatised distribution company in Buenos Aires. Subsequently the hydro plants were also privatised (Hidroelectrical El Chocón S.A., the first plant to be privatised, was also purchased by ENDESA).

Transmission was given to a number of companies. The major company is TRANSENER, which is responsible for the inter-regional HV transmission network. There are five other transmission companies, responsible for the lower voltage networks in the provinces. In addition, there are some independent transmission companies. TRANSENER is only responsible for the operations and maintenance of the existing HV system. It is prohibited from investing in the new HV lines, which is to be done using finance from private sector beneficiaries.

The pool, and the settlement system, is administered by CAMMESA whose share ownership is mixed public/private sector, with approximately equal shares for government, power producers, transmission entities, distributors and large customers. The Secretary of Energy is also the Secretary of CAMMESA. The government has the right of veto, although it has only used this once.

A new regulatory body, ENRE, was established, which is independent from government. It ensures that the various players operate in accordance with their licence conditions. ENRE is not responsible for changing the regulatory system. The Secretary of Energy has this responsibility, together with responsibility for determining strategy and broad policy for the energy sector.

As in Chile, the spot market has been important in realising the benefits from the reform of the ESI[2]. Both generators and distributors are active in the spot market. Distributors have strong incentives to sell part of their long term contracts when the value of lost load is high (the VLL varies from US$120 to US$1500/MWh) and the contracts exceed their requirements. The thermal generators declare their

[2] For example, while the thermal plants sell to EDENOR at $39.53/MWh under their vesting contracts, in late 1995 the average market price was around $25/MWh. The vesting contracts have reduced the fall in prices to final consumers, although average prices to consumers have fallen by about 12% in real terms.

variable costs to CAMMESA every six months[3]. Until March 1995 CAMMESA fixed the opportunity cost of water, but this is now done by the hydro stations[4].

CAMMESA makes the cost calculations and prepares the dispatch schedule weekly in advance. The dispatch schedule is for the thermal, hydro and so-called fault units. The latter units relate to supply interruptions when available generation capacity would be insufficient to meet forecast demand[5].

All generators which are dispatched receive the fault unit price, adjusted for losses at the appropriate node on the system. Since in the absence of supply interruptions the normal spot price is around $22-25/MWh, this provides a strong incentive for units to be available.

CAMMESA is also responsible for the settlements system. Generators receive payments for energy, capacity and ancillary services. Energy payments are calculated on the basis of the energy generated and hourly spot price at each node (allowing for losses). Three different capacity payments are made, as follows:

i. dispatch. All generators which are dispatched receive $10/MW in peak hours of their maximum generating capacity allowing for transmission constraints (e.g. installed capacity 200 MW, but limited to 100 MW by transmission constraint, payment of 100 x $10/hr, even if less than 100 MW is called for dispatch);

ii. base power. This is paid to thermal plants for each hour at which they are available ($10/MW) in specified hydrological conditions; and

iii. standby power. - Each generator offers a price to provide standby power. CAMMESA ranks the offered prices, and determines the capacity required to provide the standby power. All selected plants receive a price based on the costs of the marginally selected plant.

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[3] These prices are not allowed to exceed by more than 15% the reference price for each type of fuel (gas, gasoil, fuel oil, etc.) which is calculated by CAMMESA. To date most thermal plants have declared prices below the reference prices.

[4] Plants with large reservoirs do this every six months, while those will small reservoirs do it monthly.

[5] The fault unit price depends on the magnitude of the supply shortage, as follows:

Supply Shortage	*US$/MWh*
0 - 1%	120
1 - 5%	170
5 - 10%	240
Above 10%	1500

2.3 Uruguay

Uruguay's ESI is about to be reformed, while retaining the industry in public ownership. It is expected that UTE, the existing power utility, will be divided into three business units, all of which will continue to be owned by UTE. Each of the five generating plants (two thermal and three hydro) will be made into a separate cost centre with its own accounts. Transmission and distribution will be separate businesses. A new dispatch centre will be commissioned, which will be operated by the Ministry of Energy and Industry. Independent power projects will be permitted. A transmission pricing scheme will be introduced, and there will be open access to the transmission system. The aim of the reforms will be to deliver efficiency improvements. Competition will be encouraged in generation, while transmission and distribution will be regulated. The jointly owned (Uruguay and Argentina) Salto Grande hydro power plant will be operated directly by the State Energy Commission.

3. Transmission

3.1 Chile

The Chilean ESI consists of three separate interconnected supply systems, of which the largest is the central system serving Santiago. The following discussion relates to that system central integrated system (SIC).

Under the 1982 law, generation and transmission was unbundled as a separate business from distribution. Subsequently the companies were privatised with ENDESA owning TRANSELEC, the major transmission company. Some transmission assets are also owned by Chilectra Metropolitana and Chilquinta. An issue is that ENDESA is simultaneously the largest generator and also the major transmission company. Although in principle this could be addressed through transparent rules for the use of the transmission system, it is apparent that there is some mis-trust of ENDESA.

The 1982 law was modified in January 1990 in order to establish tariffs for the use of the transmission system. The revision established the principle that the main grid was to be paid for by generators. The rules developed the concept of "area of influence". Basically this is that generators should pay for the percentage of assets which their decisions influence. This is determined on the basis of the energy which they put into the system. Prices for use of the regional grids are different. These are set on the basis of:

- the value of new and replacement transmission lines, sub-stations etc. which are annuitised over 30 years; and
- operations and maintenance costs.

The calculations are undertaken as if the whole system was built on a green field site today, but without any design changes. The annual rental is calculated and injections to and withdrawals from the system are calculated at short run marginal costs. The tariff income then arises from the operation of the Economic Load Dispatch Centre (ELDC), with the balance being paid by generators. The annual rental is re-calculated every five years.

This system has given rise to a number of problems, including:

- the determination of the "area of influence" for each power plant;
- determination of the proportional payments for each generator (the options include payment based on the maximum energy injected by each plant in to the system on either a coincident or non-coincident basis);

- no reliability criteria have been set for the lines, sub-stations etc., which has led to dispute. The ELDC has to obtain agreement from all generators on the reliability levels. This has led to disputes as to how costs should be incorporated into the rates.

Each transmission company publishes details of its rents for the next five years, which includes an indexation formula. If a user of the system disagrees with the proposed price then he is free to go to arbitration.

The nodal penalty factors do not vary by time, which is recognised as being an issue. A load flow model is used to estimate marginal losses. The day is divided into three blocks and the year into three periods. The model is run for three hydrological conditions (normal, wet and dry). The calculated penalty factor for each node is an average figure which is used for both plant dispatch and price setting. Some generators wish to use the actual, time and location differentiated, penalty factors for dispatch. However, it is proving difficult to get agreement for change since this would disadvantage some users.

Under the reforms all generators are allowed to build new transmission lines. This effectively sets a cap on what TRANSELEC can charge for the use of the transmission system. As the system has developed stranded assets have arisen. This issue needs to be addressed.

3.2 Argentina

Following the reform of Argentina's ESI responsibility for the transmission system is spread over a number of entities. TRANSENER is responsible for the operations and maintenance of the inherited HV (220 and 500 kV) system, but not for the future development of that system, (apart from issuing technical licences for new lines). This limitation on TRANSENER's role was made in order to encourage competition in transmission services. Under the law new lines must be proposed, and financed, by the beneficiaries, i.e. generators and distribution companies. Agreement to proceed with a new line must be reached by at least 70% of the beneficiaries. The independent transmission companies can recover the investment costs of the new lines over 15 years. For the remainder of the concession period they can only charge the same operations and maintenance costs as TRANSENER.

At present it is difficult to assess the success or failure of this policy. Although two independent transmitters have been established (and one new line has been constructed and another is under construction), both of them were promoted by the government. Further, to date no private sector generator has participated in a new transmission line. There are examples of the new procedures possibly hampering the development of the transmission system. An example is the overloaded HV transmission line from Alicure to Ezeiza, with significant amounts of generating capacity in the South constrained off. While the generation companies would like to invest in a new line, to date they have been unable to agree on their relative participation and on the line's routing.

In conformity with the intention to introduce competition into transmission, TRANSENER only receives payments (via CAMMESA) for the operations and maintenance of the inherited HV system. Charges related to the replacement of the assets are excluded from the tariff since at the end of a line's life it must be replaced by an independent transmitter.

The transmission tariff has three parts; two fixed charges and one variable. First, users pay for connection to the HV system (10% of CAMMESA's revenue). Different (hourly) charges are levied according to the voltage at which connection is made, being highest for the 500 kV system. Second, all users of the 220 kV and 500 kV systems pay a fixed capacity charge, which because of the intention not to allow for the recovery of investment costs, is related only to the O & M costs of the system ($/hr/100 km, providing some 30% of revenue). Third, there is a nodal energy charge, based on the estimated losses at the node (60% of revenue).

Users of the transmission system pay CAMMESA, which in turn pays TRANSENER. The money to be received by TRANSENER is fixed for five-year tariff periods. During the first period this is fixed (by CAMMESA) at US$55 million/year.

3.3 Uruguay

The vertically integrated UTE does not have a transmission tariff. One is expected to be developed as part of its reform.

4. Possible Chile - Argentina Energy Trade

Chile and Argentina have discussed the possibility of energy trade since the late 1970s. However, substantial progress in these discussions only became possible in the early 1990s following the reforms to Argentina's energy sector. Chile had incentives to progress these discussions following the reform of its electricity industry in 1982 (and subsequent reform of its gas industry) in order to lower its costs. However, prior to the reform of Argentina's electricity and gas industries in the early 1990s, there were a number of significant obstacles to the development of trade. In particular, prior to these reforms the Government of Argentina exercised strong control over the energy sector. There were frequent changes in the key staff with whom energy trade negotiations needed to be held. In addition, there were no rules binding later staff to the decisions taken by their predecessors. These conditions meant that two of the basic requirements for trade negotiations were not met: namely, that there should be certainty and continuity in the group with whom negotiations would take place, and that negotiations should progress on the basis of earlier understandings.

Following the reforms to Argentina's energy sector, the Presidents of Chile and Argentina signed an economic agreement in 1993 which included the study of possible energy (gas and electricity) trade. Three main studies were agreed, as follows:

i *regulation*: identification of any changes which would be required to the regulatory systems in both countries in order to facilitate energy trade.

ii *technical:* analysis of the technical feasibility of gas and electricity interconnections, including their location and likely environmental impacts. The study would assist potential investors in preparing bankable projects.

iii *dispatch of generating units:* Study of how generating units should be dispatched. While Argentina preferred a system based on central dispatch, Chile had doubts on the technical feasibility of this.

These studies have assisted in unlocking the potential for the trade in natural gas. Chile agreed that dispatch would occur on the basis of generating units actual short run marginal costs. This meant that gas fired plant in Chile would displace coal fired plant and hence there would be a substantial demand for natural gas from the power sector. This was key in ensuring the economic viability of a major gas pipeline from Argentina to Chile.

Although a feasibility study has been prepared for an electricity interconnector between Chile - Argentina through the Andes tunnel, for the foreseeable future energy trade will focus on gas. Argentina is a major producer of natural gas in the Neuquen area (south of Mendoza), and also has major reserves in Patagonia and in

the northern part of the country which will shortly come into production. Two schemes for the export of gas to Chile were considered, of which the "GasAndes" project is going ahead. This has an expected completion date of early 1997. A 24 inch pipeline will cross the Andes at the level of Mendoza to provide Santiago with about 80 million cm3/d of gas. The economics of the pipeline is linked to the construction of new CCGT gas-fired capacity near Santiago, with the first unit planned for commissioning in 1998. Initially all of the gas supplied is expected to be used in the power sector, but gradually this proportion is expected to fall to around 60% as other gas markets are developed.

4.1 Argentina : Government policy on electricity trade

Although the government's role in Argentina's energy sector was substantially reduced following the reform and restructuring of the electricity and gas industries, it continues to be important for international trade in energy. This occurs in a number of ways, including:

- the government must approve any proposed gas or electricity trade. Thus, under the electricity law the Secretary of Energy is responsible for approving proposed electricity imports and exports. He is advised by the regulator, who is responsible for assessing the effects of proposals on other players in Argentina's energy sector;
- it continues to engage into inter-governmental discussions aimed to increase energy trade; and
- proposed political/regulatory agreements must be approved by the Secretary of Energy.

An example of the Secretary's role is as follows. Under the gas law exports can only be permitted if they do not compromise Argentina's ability to meet forecast domestic demands for gas. The basic criterion is that exporters must demonstrate that proven and probable reserves would maintain a production/reserve ratio of between 15 and 20 years. In order to assist with this the government seeks to ensure that the market continues to provide the appropriate price signals for additional exploration activity.

One of the government's aims is to gain open access to the electricity sectors in other countries for players in Argentina's electricity industry. The government acts as a facilitator for international trade in electricity (and gas), even though actual trade would be undertaken by the private sector. It has been discussing possible electricity trade with the Brazilian government. Because it has excess capacity, Argentina has the potential to export firm energy (which can be relied on in a normal year) and import very cheap secondary energy (in wet years) from Brazil. Any contract which is entered into would be administered by CAMMESA[6].

Finally, the government retains a watching brief to ensure that trade agreements are honoured. The energy secretariat is particularly concerned to ensure that there is transparency in proposed agreements and that the prices for imported energy are not subsidised.

[6] On its formulation CAMMESA took over responsibility for the existing electricity trading agreement between Argentina and Uruguay.

5. Uruguay - Electricity Trade

Because of its geographical position, Uruguay has been, and will continue to be, of key importance for electricity trade in the region. To date this trade has been focused on Argentina, both through the jointly owned Salto Grande plant and a 1978/9 agreement on electricity trade. Under this agreement trade has been of two types. First for "substitution" energy, which is based on differences in the SRMC in the two countries, with the cost savings being shared equally between the two parties. In the past the variation in short run costs has been between US$0/MWh in Uruguay and US$40 MWh in Argentina. Second, trade in emergency energy, with capacity and energy charges.

The 1978/9 agreement has been important, and in some years (e.g. 1992) Uruguay exported nearly 50% of the energy generated. However, various problems have arisen following the reform of Argentina's ESI which need to be resolved if trade is to continue to be important and to grow. These include issues related to Uruguay selling into Argentina's pool, to possible distortions arising from TRANSENER's transmission pricing system, and to ways in which new transmission investments would need to be financed in Argentina. These are discussed below.

- Bidding into Argentina's pool. Trade is still occurring on the basis of the 1978/9 agreement. However, UTE would like a new agreement under which it would bid into Argentina's pool. This would tend to raise prices in Argentina and lower costs in Uruguay, so while Uruguay would benefit from receiving the pool price, consumers in Argentina would lose. A similar issue has arisen in Southern Africa with the development of the SAPP raising the possibility of substantial external purchases from ESKOM's pool that would raise pool prices. It has also been identified as an issue for future sales from the Bonneville hydro project into California's proposed pool.

- Transmission pricing. As previously noted, TRANSENER's tariff relates only to the recovery of operations and maintenance costs, since it is precluded from the financing of new transmission lines. Although Uruguay presently does not have a transmission tariff, one is expected to be introduced along with the structural reform of its ESI. The tariff would include capacity charges. The Uruguayans see this as distortionary and would like to agree a common approach to transmission pricing in both countries.

- Following the reforms in Argentina, new transmission lines must be agreed by the beneficiaries and financed by the private sector. If following reform, generators in Uruguay are allowed to bid into Argentina's pool, then the beneficiaries would be Uruguayan generators and large consumers and distribution companies in Argentina which might benefit from a marginal fall in pool prices.

However, it is not yet known whether the Uruguayan generators will be allowed to invest in transmission facilities. Further, under Argentina's electricity law more than 70% of the beneficiaries from a new transmission line must agree to it if it is to proceed. Already problems have been experienced in getting generators in Argentina to agree to proposed new transmission lines. These problems are likely to be greater when agreement needs to be reached between beneficiaries in Argentina and Uruguay.

A project relating the 500 kV system which would explore the joint dispatch and operation of the Argentinean and Uruguay systems is expected to be signed shortly. It includes agreements on how water would be valued, how the SRMC of thermal plants will be calculated, and the establishment of common technical standards (these already exist for voltage and frequency).

5.1 Brazil

Although there are presently no significant transmission links between Uruguay and Brazil, a number of projects are being considered. These include a planned 70 MW interconnector with IADB financing for the converter station to address the difference in frequency in the two systems (50 hz in Uruguay and 60 hz in Brazil). In addition, the following three projects are being studied:

- a 500 kV AC line from San Carlos in Uruguay to P.Medici in Brazil. This line would be used to sell surplus energy from Argentina to Brazil;
- a 500 kV AC line from Palmar (the largest hydro plant) in Uruguay to Alegreto in Brazil;
- a 500 kV DC line from San Carlos to P.Alegre in Brazil.

The selected line will not be finalised and built by UTE. Rather it is expected to be given as a concession to the private sector. This would be the first involvement of the private sector in Uruguay's power sector. The alternative lines are being studied by Italian Consultants under financing from the IADB.

Progress continues to be made on developing possible trade with Brazil despite some major obstacles. These include the existence of many players in Brazil's power sector, which makes it difficult to identify decision takers. Further, it is difficult to identify actual generation costs in Brazil, partly due to the extensive use of subsidies. Hence trade could not be on the basis of split cost savings. Finally, there is the need to agree a charging mechanism for transmission services.

Uruguay has also been considering electricity trade with Paraguay (which has installed capacity of 6000 MW and a maximum demand of 600 MW). However, any imports would require the use of a transmission line in Argentina, which would require the approval of the Argentinean Secretary of Energy.

With the reform of UTE and the likely further development of electricity trade (the Government has agreed to an import dependency of 10%), attention is being focused on the development of appropriate contracts. It is expected that the new load dispatch centre will oversee the contracts, in addition to providing settlement services. Negotiations will be between the generators and the distribution company. Contracts would need to be approved by both the load dispatch centre and the government. This is similar to the system operated through CAMMESA in Argentina, but is more simple.

5.2 Mercosur and regional electricity trade

In 1991 Argentina, Brazil, Uruguay and Paraguay created a common market, MERCOSUR. Subsequently, the four countries signed a protocol on energy policy. This is expected to provide the framework for the further development of energy trade, including the construction of power interconnectors, between these countries.