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Development of Regional Electric Power Networks

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Development of Regional Electric Power Networks

Consultants Report

prepared by

London Economics

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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
MAPP	Mid-continent Area Power Pool
MWh	Megawatt (1,000kW)
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	Société National d'Electricité du Zaire
SRMC	Short Run Marginal Costs
ToR	Terms of Reference
TNB	Tenaga Nasional Berhad
TWh	Terawatt hour (10 ⁹ kWh)
UCPTE	Union pour la Coordination de la Production et du Transport de l'électricité
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. This report has three main objectives. Firstly, to review and better understand the experience accumulated during the operation of regional power networks, with emphasis placed on institutional, organizational, contractual, and economic aspects. Secondly, to provide ideas for enhancing the development of international electricity trade, and thirdly, to investigate the impact of the ongoing restructuring activities that many countries are implementing.
2. International trade of electricity between countries is not new. The first international interconnection was built between Germany and Austria in 1929. 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.
3. The effective development of larger international networks started in the 1950's with the creation of international networking entities both in the North American continent and in Europe. Examples are the New England Power Pool (NEPOOL), the Mid-continent Area Power Pool (MAPP) in the United States, the European Union of Producers and Electricity Carriers (UCPTE), which was created in 1951, in Europe and the Nordic Electricity grouping of producers and transporters of electricity (NORDEL) created between five Scandinavian countries in 1963.
4. At present international power networks exist in almost all continents. 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.
5. Between technically compatible systems and for relatively short interconnection lines, preference was 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.

6. 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.

7. 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.

8. The present report, prepared by London Economics with Terms of Reference written by ESMAP, and with the financial support from UK-Overseas Development Authority (ODA), focuses essentially on the institutional and economic experiences accumulated within four regional networks. These are networks in the Nordic countries (NORDEL), Southern Africa (SADC), South East Asia, a regional interconnected system in India and a "tight" US pool of the New England area (NEPOOL). Additional information gathered through literature screening were also considered from the experiences from UCPTE in Western Europe, England/Wales-Scotland, and a "loose" pool in the United States (MAPP).

9. The principal findings and lessons learned are detailed in the consultants report. These are briefly summarized in what follows.

Institutional framework

10. 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 a high degree of consensus on the operation of the pool.

Pricing principles

11. The case studies showed two broad approaches to pricing. One is to set a "fair" price, on the basis of avoided costs by one party or splitting the savings between both parties. The costs of such an approach grow 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. The other approach is for price setting on the basis of generator bids, as in Norway and England. Irrespective of the approach, it is important to agree tariffs before investments proceed.

12. Approaches to energy, capacity and transmission pricing varied. 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 case studies, transmission was not unbundled or separately

priced. This did not appear to be a constraint to trade. However, if power sector reform proceeds, then transmission pricing could become a constraint to trade.

Oversee and settle trade

13. Proper monitoring, through metering, and billing to settle trade, are essential preconditions to ensure successful and sustainable trade. In this context, metering can be a constraint to trade, but one that can be removed at low cost. Different approaches to overseeing and settling trade have been used with apparent success. These range from settlement based on theoretical dispatch calculation, to those based on bilateral contracts or through ad hoc arrangements.

Agree and enforce technical standards

14. 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.

Contract and contract enforcement

15. 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.

16. Contract enforcement may be a problem for some countries and power sectors. Problems are likely to be greatest for trade within synchronous networks.

Impact of Power Sector Reform

17. Power sector reform may increase the transaction costs of electricity trade, but should provide greater incentives. Transaction costs are slight when set against the gains from trade, and power sector reform is likely to lead to greater trade. However, it may well introduce transitional problems, due to the movement from an established trading regime to a new one.

Concluding Remarks

18. It is worthwhile to highlight the following points and issues. 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.

19. Transport of electricity, sometimes through various borders, remains a major bottleneck. Three major conditions seem 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 in a monopoly situation within

given areas, it should be regulated and international agreements should be discussed between different concerned countries so that part of the transmission regulatory regimes includes an international transit (i.e. wheeling) clause. Thirdly, some sort of international coordination between the dispatching centers of the different transmission companies will have to be put in place to ensure the technical feasibility of such international transfers of electrical energy.

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

21. Regarding international coordination between the different dispatching centers of the transmission companies, the experience accumulated within national regional pools, and in particular the "loose" pools of the US system, could provide valuable information.

22. Most international electricity trade is presently made on a bilateral basis and therefore do not require sophisticated arrangements. This situation may be different with multilateral contracts or cooperation agreements. The main issues in this regards are threefold: i/ content of the contracts, ii/ pricing principles, and iii/ sharing of risk.

23. The content of the contracts vary tremendously, the only common features included within each present contract are related to the quality of the delivered service and the price of electricity. Agreement on the technical quality of electricity delivered, and in particular the stability of frequency and voltage, will always be of prime importance when interconnecting synchronous networks.

24. In most of the present bilateral trade agreements, pricing is generally based on two principles: either the "avoided" cost or the "benefit" sharing. The two concepts are economically sound but require trust and extensive exchanges of information. Within unbundled and competitive markets structures, price based on "bidding" approaches seems more viable.

25. Risk coverage is major issue in electricity trade. The importer is generally protected though "take or pay" contracts and the purchaser through "penalties" for delivery or quality failures. However, this issue may rapidly become crucial with the expansion of international power trade. New and additional approaches will need to be developed such as cross ownership of supply plants or use of third parties providing the guaranty of bond deposit.

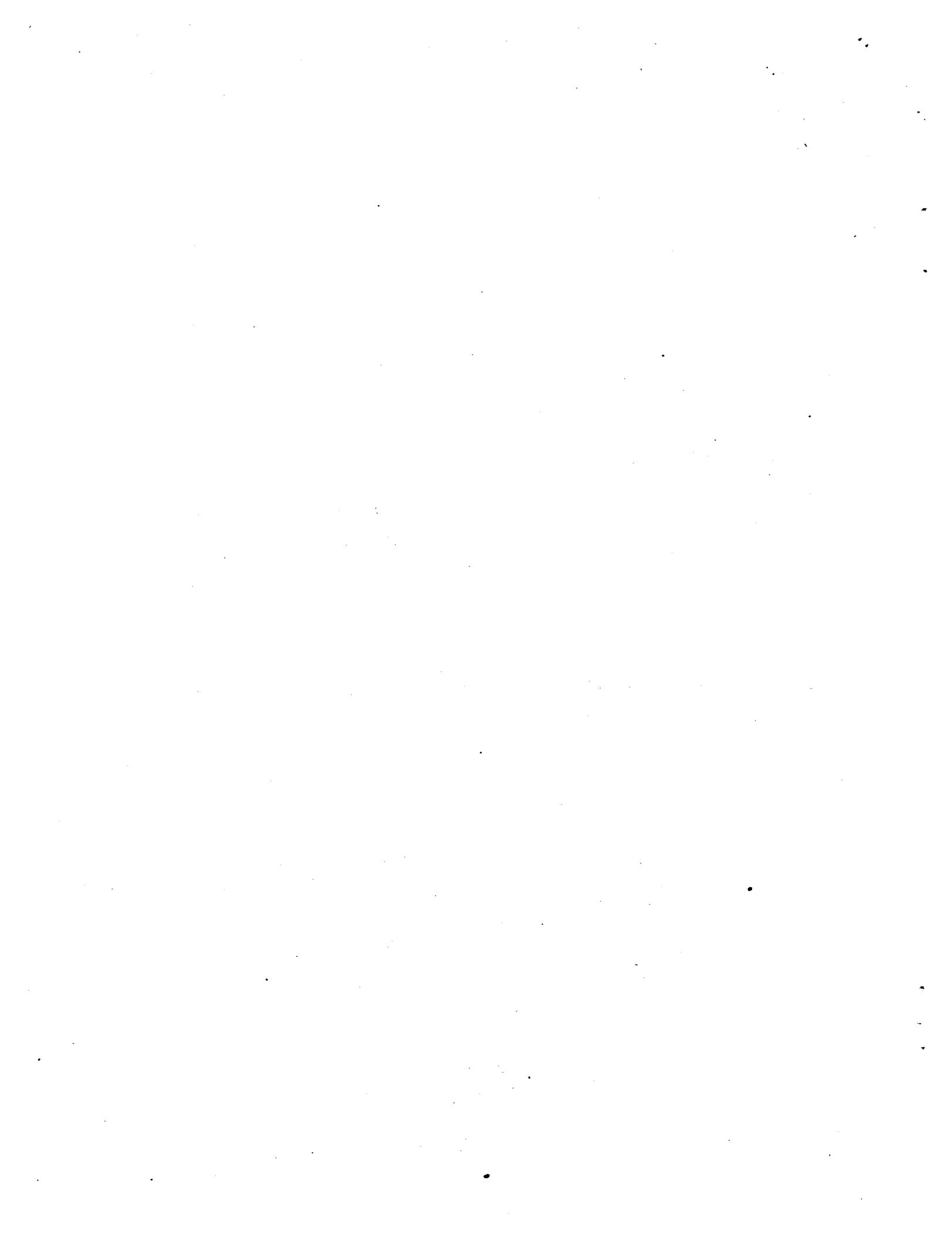
26. Harmonization of power sector structures between trading countries seems to be a prerequisite to any extensive trade. The case of the NORDEL countries serves as an illustration. The unilateral reforms implemented in Norway have drastically affected the electricity exchanges between the different countries of the network.

Issues for further development

27. The following emerging issues will require further development, in particular:
- a) The structure and operational viability of international pools (loose or tight pools) created with unbundled utilities from different countries;
 - b) The principles for setting attractive and competitive transport tariffs (for both the transmission companies and the potential users).
 - c) The regional coordination of transmission policies, including third-party access.
 - d) The preparation and enforcement of multilateral contracts with due regard to a fair sharing of risk and the settlement of disputes;
 - e) The environmental issues linked to the construction of international interconnection lines.

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

29. 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 consultants.



Review of Regional Power Networks

Summary and Conclusions *

1. This review aimed to identify whether there are constraints to development of trading networks, and if so to determine what the constraints are and how they can be addressed. It was carried out through visits to India, Southern Africa, the Nordic countries and Thailand, and through a desk study of NEPOOL in the USA.
2. The review found substantial energy trade on a short term basis. Where conditions were favourable, this could be achieved with relatively informal trading arrangements. In NORDEL, trade reached 7% of total energy under the umbrella of a "gentleman's agreement".
3. Bilateral trade is possible without complex institutional arrangements. Multilateral trade is likely to require some form of "clearing house" or settlements agency. Specific government to government agreements are most likely to be needed if utilities are owned by government, if electricity trade is a major element of exports, or if trade affects security of supply.
4. There was evidence that even short term energy trading was not being optimized. In India, very substantial benefits could be realized through additional trade between REBs. In Southern Africa, the potential benefits of cheap hydro within the region have not been fully realized.
5. There was much less evidence of long-term contracts that were sufficiently firm to influence the long term expansion programme. NORDEL aimed to avoid net trade, and the Indian REBs only traded on a spot basis. NEPOOL also requires pool members to have sufficient capacity, whether from their own resources or through long term contracts.
6. Firm power contracts are characterized by "take or pay" arrangements by the importer, and penalty clauses for the exporter if contracted energy is not supplied. Some Southern African contracts appeared too flexible to function as firm power. For example, they allowed the "firm power" to vary up and down and payment to vary pro rata. Others were short or medium term, aimed at reducing the problems of present capacity shortage rather than substituting for long term investment by the importing country. Trade between Thailand and Laos provided the clearest example of a contract that influenced the importing country's expansion programme.

* London Economics Report

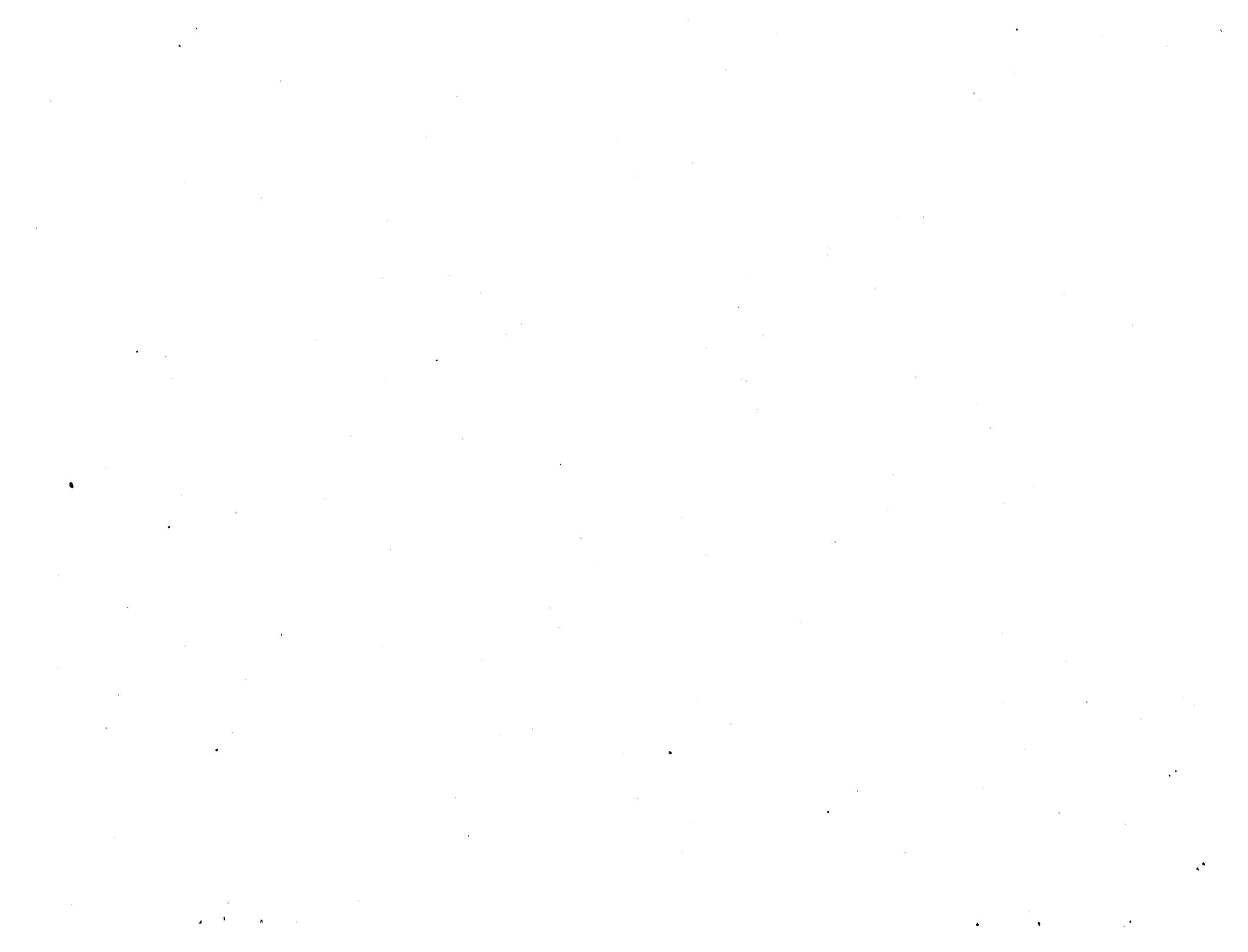
7. Again, there was substantial evidence that firm power trade was sub-optimal. This was illustrated by potentially economic investments that were not in place, including for trade between India and Nepal, and for export from Norway to UCPTE.
8. Possible constraints reviewed in the study included the institutional structure for trading to proceed; the structure of the contracts themselves, including the pricing principles and level of prices; and the risks posed by contracts.
9. Substantial trade can take place on a relatively informal basis. Formalisation, and the development of appropriate institutions, is required as trade becomes multilateral, rather than bilateral; as trade becomes long rather than short term; and as markets are unbundled and trade takes place within a power pool.
10. A variety of pricing arrangements were found. All could set prices at levels that allowed trade to proceed. Prices that were based on avoided cost by one or both parties required a good deal of information. Where the electricity supply industry moved on to a more commercial basis, trust in this information was reduced. As a result, power sector reform could require a substantial increase in the transaction costs, due to the need to audit declared costs. Alternatively, trade could be based on bid prices, with no requirement that these be cost reflective.
11. Transmission was often integrated within utilities, and not separately priced. Where it was priced, for example for wheeling contracts, transmission pricing tended to be unsophisticated, and ineffective at providing accurate price signals on the marginal costs of losses and transmission constraints.
12. The review could not analyze transmission costs in sufficient detail to identify whether this was a constraint to trade. *Prima facie*, the costs of transmission form a high proportion of the cost differential between generation in exporting and importing countries. It is likely that the failure to unbundle and accurately price transmission services is a constraint to trade.
13. The risks posed to both parties appeared to be the most substantial block to firm power trade proceeding. An exporting country is required to make major long term investments. It faces the risk that it will then be driven down close to short run operating costs, and be unable to recoup its sunk capacity costs. An importing country faces risks to reliability of supply if it depends on imports to be able to meet maximum demand. Although it can pass on the costs of any disruption to supply through penalty clauses, but it may be unable to enforce them.
14. These risks are very similar to those faced by an independent power producer (IPP) selling to a vertically integrated utility. Two solutions are possible:

- vertical reintegration, through ownership by the importing utility or country. For example, Thai investors are likely to have a large equity holding in the next generation investment in Laos.
- steps to enforce the credibility of long term contracts, for example through depositing bonds or irrevocable letters of credit with a third party.

15. The ability to enter into and enforce long term contracts depends in part on the relative strengths of the two parties. Where a generating plant is selling across a border to a major vertically integrated utility, its bargaining strength may be low. However, when generation is unbundled in the importing country then all generators may face similar risks. For example, both Swedish and Norwegian generators have a similar interest in ensuring that the Norwegian pool company meets its contractual obligations. Unbundling may therefore assist the development of firm power trade.

16. The study faced difficulties in looking at the impact of power sector reform since only one case study, NORDEL, had been through recent reform. That case study showed the possibility of disruptions to trade as power sector reform is implemented. Pricing principles previously agreed were no longer appropriate and new approaches to pricing trade needed to be agreed.

17. The longer term impact of power sector reform may be more positive. Utilities will have improved incentives to minimize costs, and so to maximize trade where it is least cost. As discussed above, the balance of power between generators and purchasers of bulk energy may become more equal, and so assist in reaching and enforcing contracts. The private sector is likely to be more familiar with managing and pricing risk. Data from outside our case study countries reinforced this analysis that the long term impact of power sector reform will be positive.



Introduction and Definitions

1. The objective of the study was to identify the major issues which need to be addressed for the enhancement of regional electricity trade. Possible issues include: policy/political, economic, commercial, and technical issues. Furthermore, given the present impetus for power sector reform, it was also decided to consider its implications for electricity trade.
2. After reviewing relevant literature, five regional power networks were studied:
 - India, as an example of electricity trade between the Regional Electricity Boards (REBs);
 - Southern Africa, as an example of a multilateral regional power network;
 - Norway, to better understand: (i) the cooperative agreement between Scandinavian Countries (NORDEL) and, (ii) the impact of the Norwegian restructuring.
 - Thailand, to obtain an overview of trading arrangements in South East Asia and,
 - an example of US tight pool: NEPOOL.
3. For each case study the overall structure of the electricity sector is described together with the arrangements for electricity trade. This includes interconnection capacity, the volume and nature of trade, payment, and institutional arrangements. Summary information is provided in the report and full case study details are included in Annexes (including an additional example of loose pool (MAPP) prepared by ESMAP).
4. The main focus of the study is on how utilities use regional interconnections to change operating and capacity costs of generation. Electric utilities provide a range of generation services - capacity, energy and reserve - and are often responsible for ensuring new capacity is made available as required.
5. Energy, reserve and future capacity could all be met by the utility itself. Alternatively, where physical connections exist or could be built, the utility could enter into arrangements for these generation services to be supplied by another utility, and so alter its own decisions on plant operation and capacity expansion.
6. Examples of regional networks include:
 - trade between countries, for example Zambia and Zimbabwe;

- trade within countries. For example, India has five largely separate regional grids, with some limited interconnection and trade; and
- trade within closely integrated networks. For example, NEPOOL is an arrangement for energy and capacity trading between some, but not all, of the generators, within a strongly interconnected part of one of the two major interconnected areas in North America.

7. In some cases, trade is conducted through bilateral contracts. In others, it involves the creation of a wholesale market for energy, that is a "pool". The term pool is commonly used for a structure where energy is traded through a spot market. That can cover all energy (as in England and Wales) or only energy at the margin (as in Norway). The pool may specifically exclude capacity (as in NEPOOL, where capacity is only traded in the secondary market), make separate payments for capacity (as in England and Wales) or bundle it into the spot energy price. Given these important differences, the text describes some of the key features of the pools covered in this study.

8. As pool arrangements become increasingly formal and long term, they also increasingly restrict the generators' freedom. Table 1.1 illustrates ways in which pools can become "tighter", involving increasing delegation to a central authority. There is no consensus on the precise definition of tight and loose pools. In this report, a tight pool is taken to be one with central despatch, and a loose pool one where despatch decisions are retained by the participating utilities.

9. Regional networks require physical interconnections. Here it is referred to transmission where a line remains in the boundary of a State or country; to an interconnector, where a line crosses a state or country border; and to wheeling where transmission services are provided by a third party, rather than the exporter and/or importer of bulk energy. Wheeling typically arises when power is exported from one country and transmitted across a second, for supply to a third.

Table 1.1 Characteristics of Tight and Loose Pools

Loose	Function	Tight
By utilities, with trade at borders	Despatch	Centrally controlled for whole pool
Free bidding	Costs for despatch	Capped or audited costs
Bilateral	Settlement	By pool authority
Unregulated, or set by bilateral contract	Operating reserve	Pool requirement with penalties
Unregulated, or set by bilateral contract	Installed capacity reserve	Pool requirement with penalties
No co-ordination	Maintenance scheduling	Pool controlled with penalties
Independently by each utility	Expansion planning	Carried out by the pool
Reserved for utility, trade at borders	Transmission network	Mandatory third party access

Generalities on Costs and Benefits - Literature review

10. Utilities can use interconnections to trade reserve, economy (non-firm) energy and firm energy. This section describes in more detail the range of benefits from regional interconnections, and the costs associated with them.

11. In practice of course all benefits consist of either energy, or the potential to trade energy. However, a fundamental distinction can be drawn between relatively short term and opportunistic trade and firm, long term trade. The former allows trading countries to alter their despatch decisions. The latter allows them to alter their decisions on system expansion and new capacity investments. Much of the discussion below focuses on the distinction between energy and firm power trade.

12. Acceptable reliability can be achieved by an interconnected system with a lower capacity reserve margin than if the networks operated independently. Lewis (1990) gives the example of a 600 MW saving from the interconnection of two 4000 MW systems (comprised of 220 MW units). Another advantage is that the size of each generating unit in an interconnected system can be larger, while still meeting independent system reliability standards. This can produce considerable economies of scale.

13. There are three reserve capacity services that are typically contracted for:

- emergency energy to be supplied at cost for a limited period (often 6 hours);
- scheduled outages to be covered by supply from another utility; and
- a proportion of spinning (immediately available) reserve.

14. If a utility faces a higher short run marginal cost (SRMC) of generation at a given time, but can purchase from a utility with a lower SRMC after allowing for transmission costs, a saving can be made. This trade in economy energy arises from lower fuel costs or the availability of more efficient thermal units. Where it is supplied from hydro energy in excess of that provided as firm (guaranteed) energy, it is known as secondary energy.

15. Longer term savings may arise from differences in capacity mixes. For example, the required storage of a hydro-based system in the dry season can be lowered by providing access to thermal power. This requires something more than a non-firm "as available" contract: it can be in the form of a commitment to supply a proportion of a fixed annual supply during certain months. The scope for cost savings is also increased where two utilities face different load shapes.

16. The interconnection of largely thermal with largely hydro systems allows energy banking. The thermal-based system transmits energy to the hydro-based system during the former's off-peak periods. This displaces hydro-power allowing water to be stored or banked in reservoirs, which can then be used to provide power to meet peak demand in the thermal system. Where payment is through reverse energy exchange rather than purchases, this is known as energy interchange. Energy is exchanged rather than sold - with cash payments only being made if an outstanding balance is held after the contractual period.

17. Firm power agreements stipulate a specified amount of power and associated energy. This constitutes part of the seller's planned load, and is typically sold on a "take or pay" basis. The energy component may be base load or at a lower specified load factor over a given period. The actual cost per kWh is necessarily higher with firm than non-firm energy, as the basis for pricing in the former (which is guaranteed and hence may require capacity additions) will be LRMC while the latter is typically SRMC. In general, long term firm power contracts (up to 40 years) have a higher value than short term contracts, as they can substitute for building own capacity.

18. Economies of scale in unit size are reached relatively early. The unit costs per megawatt capacity in fossil plants typically fall by some 25% when plant sizes double from 110 MW to 220 MW. Economies of scale may be fully realised with plant of approximately 500 MW, and the size at which economies of scale are realised has been declining with developments in combined cycle gas turbine technology.

19. Joint planning of capacity additions together with firm power contracts and coordinated despatch allows interconnected systems to function as one large system. This, in turn, permits larger average unit sizes, and hence economies of scale. This may be significant for small developing country utilities. Some economies of scale can also be achieved without coordinated despatch, simply through utilities using interconnection to permit joint development of specific projects.

20. Trade across an interconnector should increase until the marginal benefits - from displacing more expensive capacity, or from additional sales - equal the marginal cost of transmission across the interconnected network. The same argument applies to expansion of an interconnection, where costs of new generation and transmission will need to be taken into account.

21. Some costs of interconnection are fixed - this includes the physical costs of building and maintaining interconnections. Interchanges between linked grids will be affected by system disturbances or unexpected load variations, and this necessitates additional power monitoring, as well as the installation of suitable automatic generation control (AGC) equipment. These costs rise as connections increase in voltage, length and number; they remain whether the network is used or not.

22. Operating costs also increase as interconnection deepens. Costs are of three main kinds:

- increased losses and maintenance costs, where interconnections require transmission over longer distances;
- operating costs incurred by greater harmonisation of systems, such as the adoption of standards that would not otherwise be regarded as optimal. For example, frequency control in the UCPTE system is ± 0.02 Hz, while in the UPS of Eastern Europe it was ± 0.2 . Existing connections are through back to back DC links, and synchronous connections would entail adoption of new standards; and
- transaction costs of entering into, monitoring and enforcing contracts. A system such as NEPOOL, which coordinates through audited costs rather than through price bids, incurs high monitoring costs. Gegax and Tschirhart (1984), in their study of 83 utilities, find transactions costs to be statistically highly significant in explaining why regional power networks fail to arise.

23. A number of attempts have been made to quantify the net benefits both of proposed interconnection schemes and those already in existence. These primarily relate to North America, and so to the pooling arrangements typically found there. A brief review of the literature is present below.

24. The notion that the existence of regional power networks (and the development of power pooling within them or parts of them) lowers cost has been challenged by Christensen and Greene (1978). They undertook an econometric study of the costs of production of isolated companies and those within formal US pools using 1970 data. No evidence of lower production costs was found leading to the conclusion that "... savings from increased coordination have proved to be illusory" (p152).

25. These results were subsequently criticised for their failure to include system reliability as a potential gain from pooling (Cramer and Tschirhart, 1984) and for the quality of the data (Joskow and Schmalensee, 1983). As system reliability can be the major gain from interconnection, this is a serious omission¹. However, the most powerful criticism is made by Mulligan (1985), who argues that focusing on generation as opposed to electricity supply cost fails to capture the effect of trade via the regional network. Utilities with high marginal generation costs do not generate; they purchase from low cost producers via an interconnector.

¹ Montfort (1991) notes that only 7% of UCPTE total production is traded "emphasizing the primary role of interconnection in providing security and reliability of operation" p202.

26. On the basis of a study of pooling in the US, the US Department of Energy concluded both that there were clear gains from pooling and that these would increase as the degree of coordination increased (from loose to tight).² Given that this reflected the views of much of the industry, the key question is why increased coordination has not occurred. Joskow and Schmalensee (1983) suggest that "Although it is generally agreed that US electrical utilities could realize additional savings by more extensive coordination, the magnitude of such potential savings is uncertain.

27. Opportunities for productive increases in coordination are not evenly distributed around the country or among utilities. The greatest potential savings appear to be in small systems not currently full participants in planning and coordination activities. Disagreement continues over the net benefits of moving from informal pooling arrangements, bilateral power exchange contracts, and joint ownership of generation and transmission facilities to formal tight pools such as NEPOOL" (p69).

28. The question of what determines the value of increased use of power pooling to a utility is investigated by Gegax and Tschirhart (1984). Their linear econometric model is estimated on data from 83 utilities in the 19 formal US power pools. The extent of pooling in these ranges from loose to tight - where the degree of cooperation is reflected in the extent to which capital is pooled. The statistically significant variables explaining the proportion of generating capacity from plants jointly owned with other pool members are the:

Variable	Sign of estimated coefficient
number of firms in each pool	-
dummy for gas and electricity supply	-
relative size of the firm	-
standard deviation of firm size within pool	+
favourability of regulation within state index	-
dummy for public ownership.	+

² Power pooling: issues and approaches (1980).

29. The authors argue that transactions costs are captured by the number of firms in a pool, and whether each has joint gas and electricity interests. The former is a reasonable (if necessarily indirect) measure of such costs, although the latter could just as easily capture the effects of large firm size. Relatively large firms - which presumably are able to achieve scale economies without pooling - are less likely to share capacity via the network. The positive sign of the standardized deviation of firm size variable receives little comment. A possible interpretation is that large firms are less likely to join pools, but if they do, pools with firms of diverse sizes share the most capacity (perhaps as a result of generation complementarities). Favourable state regulatory environments are found to lower the extent of pooling - arguably because the need for pooling is reduced through lack of downward pressure on profitability. This does not, however, answer the question of whether differences in regulatory environments across states affect pooling.

30. Rather than investigate the factors determining trade, some researchers have attempted to estimate the gains from trade by modelling generation and transmission at a disaggregated level. Rogers and Rowse (1989) provide a comprehensive analysis of the likely gains from system integration in Canada for 1990-2020, using a multi-period linear programming model. They conclude that long-term trade brings a cost reduction of some 5% (over regional self-sufficiency) for the country as a whole. This cost saving is, in fact, rather higher than that estimated by other authors.³

31. The main reason why savings are limited for the country as a whole is that the cost of establishing long distance transmission is high, whereas only some regions have sufficient diversity to make interconnection attractive. Indeed, restricting the analysis to utilities with complementary (hydro, thermal) generation - in this case Saskatchewan Power and Manitoba Hydro - Rowse (1981) indicates cost savings of approximately 10% of total expenditure over a 10 year period.

³ Roger and Choudhory (1981) and Uri (1976) find savings of approximately 1%.

Case Study Findings

Introduction

32. Detailed case studies were carried out in three regions; India, Southern Africa and NORDEL. In addition, a brief visit was made to Thailand, to discuss interconnection between Thailand and Laos, and Malaysia. A desk study was carried out of NEPOOL, in the USA. These case studies form the main source for this report, although other sources (including data from the UCPTE) have been used where appropriate. Maps of the case study locations are given in Annexes.

33. This section briefly describes the features of the case studies. These include background data on the electricity supply industry; on the arrangements for electricity trade; and on the scale and nature of trade. More qualitative conclusions are drawn on the benefits from trade, and the possible extent of unrealised benefits from trade.

34. The case studies had important differences that should be borne in mind. They were selected to give a wide geographical coverage, and substantial variation in per capita income and electricity consumption. They also differed by:

- type of interconnection. In some cases, there were synchronous connections that required greater coordination between participants. In others, links were through DC lines or through connection of a supply area to a different synchronous network, and its simultaneous disconnection from another network. In many cases, there were both. For example, in India, the study focuses on (DC) links between regional electricity boards (REBs), rather than on the (synchronous) trade within REBs;
- whether or not they crossed international borders. Trade within one country had the advantage of a common set of national laws, and the less tangible advantages of common culture and language; and
- market structure. In most developing countries trade is between utilities with a high degree of horizontal and vertical integration. In other case studies, power sector reform had led to a relatively high level of unbundling, with commercial relations between generators, a transmission company, and distribution and supply companies.

35. The characteristics of our case studies are summarised in Table 3.1 below. Further details are given in relevant sections of the report, and in Annexes.

	Synchronous link	Link across national border	High degree of vertical integration
India	x	x	✓
Southern Africa	-	✓	✓
NORDEL	-	✓	-
NEPOOL	✓	x	x
South East Asia	-	✓	-

x = no

✓ = yes

- = mixed

India

36. The Indian power system has an installed capacity of some 72,000 MW. After allowing for poor availability and fuel quality, the system can supply a maximum demand of 49,000 MW. 28% of the capacity is hydro and the rest thermal. The supply is chronically short of demand (estimated by some as 15 - 20%).

37. Over 96% of the electricity supply industry is in public ownership. The industry is dominated by vertically integrated utilities at State level, known as State Electricity Boards (SEBs). These State level utilities are grouped into five synchronously connected Regional Electricity Boards (REBs). The SEBs operate their own generation, and have contractual shares in plant owned by central government. They also trade with other SEBs.

38. The Indian power sector is characterised by a high level of capacity deficiency. This constrains trade, since there are relatively few situations where there is surplus energy to trade. It also contributes to grid indiscipline; during peak periods, SEBs are reluctant to shed load to the degree required. As a result the frequency tends to fall during peak periods, sometimes to below 48 Hz.

39. The case study focuses on trade between REBs. The main inter-regional links are DC. Those that are in existence, or under construction, are set out in the table below.

Inter Regional Links	
Between regions	Link capacity MW
South - West	1000
North - West	500
East - South	500
North - East	500

Source: PowerGrid

40. There is a high degree of central planning, with the planning focus being the optimal development of each regional grid as a separate entity. The concept of planned exchanges of power, and the eventual development of a national grid remains a long term general objective only.

41. In addition, there are a number of lower voltage AC links, used to arrange radial supplies. International connections are minor, although a 132 kV link with Nepal is under construction.

42. Although the regional grids in India are chronically short of capacity, these shortfalls do not all occur simultaneously. There are occasions when some grids may have an energy surplus whereas a neighbouring grid has an energy shortfall. In most regional grids in India, the existence of hydro electric capacity allows at least some storage of electrical energy (by holding on to water in the reservoirs when excess thermal energy is available). As a result, the present benefits from trade are primarily a reduction in unserved energy. There is also potential for reducing generation costs (primarily in off-peak periods).

43. In the longer term, there may be wider potential for reducing generation costs through developing hydro or other low cost generation for export to other REBs. The volume of inter-REB trade at present is very low, and less than 0.5% of gross generation in India.

44. Inter-REB electricity trade is entirely on an opportunity basis. Trading arrangements are relatively informal, and vary between REBs. In the case examined, trade was coordinated by the Regional Load Despatch Centre (RLDC). RLDCs identify any surplus within their region, usually due to SEBs not requiring their full contractual entitlement from central plant. This

surplus is offered to the neighbouring RLDC. Both RLDCs independently inform PowerGrid (operators of the DC link) of the agreed trade. PowerGrid only implements the trade if both statements agree.

45. The trade is priced on the basis of the tariff for centrally owned plant. The RLDC offering energy quotes the tariff for the plant concerned. The RLDC importing energy quotes the tariff of its marginal central plant. If it is in deficit, the price of the most expensive central plant is quoted. There are no "distress sales" where the price exceeds that of the most expensive plant. Trade proceeds if there is a price differential, and the benefits of trade are evenly split between the two SEBs concerned.

Southern Africa

46. The Southern Africa case study looked at interconnections between Zaire, Zambia, Zimbabwe, Botswana and the Republic of South Africa (RSA). Energy demand in the RSA dominates demand in the region. The long term features driving trade are likely to be exports of cheap energy from hydro sources, principally to the RSA. In the short and medium term, exports of energy using the RSA's surplus thermal capacity also play a role in alleviating the impact of drought on hydro generation in neighbouring utilities.

47. The generation and cross-border interconnection capacities of the five countries are:

- Zaire: 2,600 MW of hydropower with substantial potential for further development. Zaire is linked to Zambia through a 220 kV line;
- Zambia/Zimbabwe: an integrated hydro/thermal system with 4,000 MW capacity. Trade is primarily through the 330 kV network at Kariba, and constitutes the largest electricity trade in Africa. A 400 kV link with RSA is planned through the Bulawayo:Matimba line;
- Botswana: 207 MW, all coal-fired thermal plant. Botswana has 132 kV links with RSA and a 220 kV link to Zimbabwe; and
- RSA: 36,000 MW, almost all coal-fired thermal. Connections to Botswana and planned connections to Zimbabwe, as described above.

48. Each country has a vertically integrated utility, which has an effective monopoly in electricity generation, transmission and distribution. Private investment in generation is being encouraged. There are also moves to enable utilities to operate in a more commercial manner. More fundamental reform, encompassing unbundling and ownership change, is not a high priority. In the long term, a regional power pool is planned.

49. There are a large number of contractual agreements covering trade. These are predominantly bilateral. On occasion there are three parties, when trade involves wheeling across another country. Although there is no formal coordination of electricity supply, in 1992 the three SADC utilities (ZESA, BPC, ZESCO) formed an Interconnection Operating and Planning Committee (IOPC). It is now intended to extend IOPC cooperation and a new IOPC was formed in Gaborone, Botswana, in January 1994 by including RSA in its membership. Other utilities in the region may also apply for membership. The principal mandate of the new IOPC is to (i) share information and knowledge, (ii) develop common planning and operation procedures, (iii) coordinate the planning, installation and operation of the generation and transmission facilities, and (iv) accept wheeling. Thus, the present concept is to develop the capability of the IOPC as a regional organisation for coordinating resource planning and load despatch.

50. Three categories of electricity trade are recognised in Southern Africa; emergency supply, surplus energy, and firm energy. Emergency supply is for limited periods. Surplus energy requires demonstration that the importing country has sufficient capacity, and is simply benefiting from cheaper SRMC in the source country. Firm power supply is for longer periods, and attracts a higher price. Some contracts for firm power supply may not realise the full benefits of firm supply.

51. Substantial benefits are realised from trade. The electricity trade between Zambia and Zimbabwe is the largest such arrangement in Africa, averaging about 460 MW and 2328 GWh over the last 15 years. It has been the second largest earner of foreign exchange for Zambia. Among the benefits from interconnection are substantial saving on reserve requirements, economics of scale in the Zambia:Zimbabwe system, pooling of hydrological risk, and the opportunity to exchange economy energy.

52. Transmission charges are typically bundled into energy charges. Separate wheeling charges exist when power is being exported from one country, across another, for sale to a third. Wheeling charges include a contribution to fixed costs and a charge for losses at a constant percentage of the energy wheeled.

NORDEL

53. The NORDEL region covers the Nordic countries. Excluding Iceland, which has no electricity trade, these are Denmark, Finland, Norway and Sweden. These four countries produced 336 TWh of electricity in 1990. Per capita electricity consumption was the highest in the world - roughly three times the average level for the European Community.

54. NORDEL is a synchronous network with both AC and DC connections between member countries. Peak demand in NORDEL is approximately 50 GW. NORDEL is also connected asynchronously to the UCPTE (max. demand c.250 GW) and to the UPS system of the former

Soviet Union (max. demand c. 230 GW). There is also consideration of a subsea connection to the UK (max. demand 55 GW).

55. The generation base varies substantially between NORDEL countries. Denmark's capacity is almost entirely thermal. Norway's generation is 99% hydro. In both Finland and Sweden, over 50% of capacity is hydro. The potential for seasonal trade is high. In addition, average generation costs are low, and there is potential for export beyond NORDEL's borders.

56. Ownership structures are summarised in Table 3.2 below. In brief:

- Denmark has a high level of municipal ownership. In practice, it is best regarded as two vertically integrated utilities, covering the West and East of the country the West being connected synchronously to UCPTE;
- Sweden also has multiple generators, but generation is dominated by Vattenfall, a public company. Responsibility for the transmission grid and for interconnection was recently separated from Vattenfall. Continuing power sector reforms are envisaged, with the development of a power pool;
- Finland has a dominant public generator, IVO. Responsibility for the grid was separated from IVO in 1992. It continues to operate international interconnectors; and
- Norway has made the furthest progress on market reform. There are multiple generators, supplying energy under long term contracts and through a pool. A public transmission company operates the grid, the pool and most interconnectors.

Table 3.2: Ownership structure, 1990 (Percentage of Generation/Customers) Source: Hjalmarsson 1993.								
	Denmark		Finland		Norway		Sweden	
	Gene-ration	Distri-bution	Gene-ration	Distri-bution	Gene-ration	Distri-bution	Gene-ration	Distri-bution
State	0	0	46	0	25	0	55	11
Municipalities/ Counties/Coops	98	100	18	75	38	80-90	20	64
Private	2	0	36	25	38	10-20	25	23

57. Interconnection trade is 7% of gross generation. With the exception of a few long-term contracts, almost all power is transmitted on a day-to-day basis. There has been a general policy of avoiding net trade over long time periods, although this is breaking down.

58. Interconnection capacity is roughly 18% of generation capacity. The average load factors on the interconnectors are low. However, as much trade is seasonal, interconnection capacity can be a constraint at certain times of year.

59. NORDEL provides a framework for cooperation and coordination, but it has no formal powers. Its membership is limited to prominent members of the national electricity supply industries, and members do not represent the governments of their respective countries. Trade has traditionally been conducted on the basis of bilateral, informal "gentleman's agreements".

60. Payment has traditionally been made through (a) sharing information on marginal operating costs, and (b) sharing the gains from trade. Following the industry reforms in Norway, this has been breaking down, as there is less mutual trust in the cost information provided. Trade has moved towards more commercial pricing arrangements, on the basis of offer prices for bulk energy, which may or may not be cost-reflective.

61. Recently, Norway had to abandon proposals to wheel electricity from its north through Sweden. They were unable to negotiate wheeling terms, and had to construct new transmission lines instead.

62. The great majority of trade is short term energy. This reflects a policy stance by the governments of avoiding net trade, and so largely restricting trade to seasonal interchange. As a consequence, trade has not been sufficient to equalize energy prices in neighbouring countries

(after allowing for transmission costs). The potential for export to the UCPTE network has also not been realised, in part because of restrictions on wheeling.

NEPOOL

63. The New England Power Pool (NEPOOL) consists of 96 utilities in six New England states. NEPOOL operates as a tight pool, with centralised despatch, load forecasting and planning, and cooperative maintenance scheduling. In doing so, it has overcome many of the constraints faced by looser regional power pools.

64. NEPOOL has nearly 26,000 MW of plant capacity, and is part of the interconnection that covers most of the eastern part of USA and Canada.

65. Pool members must provide themselves with sufficient generating capacity, either by ownership or by contract. "Free Riding" on the pool through insufficient capacity is discouraged through penal pricing.

66. Much of NEPOOL's capacity is oil and gas fired. Nuclear plant accounts for 25% of installed capacity, and 38% of generated output in 1992. NEPOOL imports a significant amount of energy from other regions; purchases are coordinated by the pool. Non-utility independent generation is also important.

67. NEPOOL is governed under an agreement made by all of the participating utilities. The focus of this agreement is organisational, not operational. The NEPOOL Agreement sets up a management committee to oversee the overall management of the pool, and operations and planning committees to direct specific activities. The management committee acts as the dispute resolution board for the pool. The operations and planning committees report to the management committee.

68. Functionally, NEPOOL operations are split up into:

- New England Power Exchange (NEPEX);
- NEPOOL Billing; and
- New England Power Planning (NEPLAN).

69. NEPEX is responsible for centralised despatch of plant, and maintaining security of supply. NEPOOL Billing monitors and accounts for all energy and services transactions within the pool, and ensures that pooling benefits are distributed to the utilities fairly. NEPLAN provides load forecasting services, and evaluates potential generation and transmission projects.

70. The pool calculates a despatch for each utility as if there were no pool, and a despatch for the pool as a whole. Utilities generating more than is required for their own despatch are paid the SRMC, and those generating less pay their own avoided cost. A savings fund equal to the difference in cost between pool despatch and the sum of individual dispatches is then distributed to all members, in proportion to the volume of trade with the pool for each one. Those utilities whose individual despatch shows a capacity deficit pay a penalty rate for imports, to cover capacity deficits.

71. Benefits from trading have primarily resulted from the pool's ability to provide reliable supply with limited reserve margins. NEPOOL utilities have also benefitted from trade with Hydro Quebec and other pools. These purchases have risen rapidly, and the savings now rival those of internal pooling. Purchases from outside sources (such as Hydro Quebec) have proved easier for NEPOOL to negotiate than for each participating utility (some of which are very small in size) independently. Connections with Hydro Quebec are asynchronous, reflecting NEPOOL's concern with Quebec's security of supply.

72. The large number of participating utilities necessitated centralised despatch, rather than despatch by each utility's chosen schedule. The number and diversity of the participants also focused attention during the creation of the pool on institutional issues. The resulting committee structure, while in some ways cumbersome, has given NEPOOL considerable flexibility. This has allowed it to adapt to several significant changes, including the integration of numerous small utilities (forced by court order), the growing importance of imports from Canada, and other challenges.

73. NEPOOL has benefitted from similar regulatory structures across its six states, careful attention to organisational design early on, and lack of competition between vertically integrated member utilities. Institutional and regulatory constraints have prevented NEPOOL from expanding into the eastern provinces of Canada, despite the economic benefits available. The costs of meeting a new set of regulations is felt to outweigh the benefits to be had from pooling with Canadian utilities in Nova Scotia and New Brunswick.

South East Asia

74. The case study for South East Asia has been covered in less detail than other case studies, but it was of interest in having agreements for firm cross-border trade.

75. Thailand has a power system of 11,000 MW, operated by the Electricity Generating Authority of Thailand (EGAT), with a small share of energy (8%) from hydro. Laos has 90 MW of installed capacity for the domestic market. It also has 300 MW of hydro dedicated to export to Thailand, and a further 1500 MW for export is under discussion and/or development. Malaysia has a developed power sector, but a relatively weak link to Thailand.

76. Because the Laotian system is so small compared with EGAT and the size of the link relatively large compared with the Laotian system, Laos becomes in effect a small distributor connected to the Thai system; its operation has virtually no influence on the interconnected system. It would be difficult therefore for Thailand to perceive any operational difficulties arising from the connection to Laos, and this is indeed so.

77. The AC interconnection between Thailand and Malaysia failed on a number of occasions because of the difficulties of maintaining synchronism between two relatively large systems using such a weak link. Attempts to operate a synchronous interconnection have been abandoned, and it has been used for radial supplies. A 300 MW DC link is under active consideration.

78. Trading with both Malaysia and Thailand is all on an opportunistic basis, with the exception of the Nam Gun power station and the proposed new hydro projects. The contract proposed for the new developments obliges the Laotians to provide firm power, and lays down penalties for failure to do so. This approach would probably deliver lower benefits than a more flexible approach with less security of delivery under the contract.

Conclusions

79. The case studies provide a good deal of information. Three broad conclusions can be drawn. First, most of the benefits from trade presently being realised are economy energy. NORDEL has traditionally pursued a policy of no net trade; NEPOOL requires members to meet their own capacity requirements through own generation or contract; Southern Africa predominantly trades economy energy, and some of the firm power contracts do not appear firm enough for capacity planning; and the Indian REBs take steps to ensure that they are not selling capacity to neighbouring REBs with capacity deficiencies. Although Southern Africa gives some examples of firm power trade, the main example of such trade was Thailand:Laos.

80. A second striking point was the role of hydro as a motor for trade. All case studies included a prominent role for hydro. Even in NEPOOL, which has relatively little hydro itself, the benefits from external trading (principally with Hydro Quebec) have risen to the point where in 1992 they matched the benefits from centralised despatch within the pool.

81. A third conclusion was that in most cases the benefits of trade were not being fully realised. Examples of this are given in the case studies. They include the failure to optimise trade between the Indian REBs, the failure of NORDEL to develop exports to the UCPTE (or on occasion to transmit electricity economically within NORDEL), and the failure of NEPOOL to expand when this was apparently economic.

Constraints

Introduction

82. All the case studies identified instances where opportunities to increase benefit from electricity trade were not being taken. This was reflected in inadequate interconnection capacity; inadequate use of the available interconnection capacity; and poorly structured contracts for the energy that did flow along interconnectors.

83. The case studies sought to identify the constraints to the development of regional power networks. Many specific constraints were identified, and these are discussed in detail in this section, in particular: the institutional arrangements for trade; the ability to enforce contracts for bulk electricity and its transmission; and the structure of those contracts.

84. This report also examines the risks in electricity trade, and the difficulties that arise when there is an imbalance of risk. Technical issues are briefly, summarised. The impact of power sector reform and of environmental issues are dealt with in succeeding sections.

85. An over-riding theme of the case studies was that the key constraint was a lack of trust between the parties to interconnection, usually but not always, governments. Utilities were unwilling to alter their despatch decisions, and even more so their decisions on capacity expansion, on the basis of another utility's supply.

86. The themes discussed below can be considered as ways of increasing trust between the parties to an interconnection. Trust will be increased by providing a formal structure for trade; correctly structuring the contracts for trade; and ensuring the contracts can be enforced.

Institutional arrangements

87. In order for electricity trade to proceed it is necessary to:

- set the framework within which trade will be conducted;
- agree pricing principles;
- oversee and settle trade;
- agree and enforce technical standards for synchronous networks; and
- arbitrate between member utilities.

88. An important issue is whether these requirements can all be met through bilateral contracts or whether new institutions need to be developed for electricity trade to proceed. The findings of our case studies were mixed.

89. **Institutional framework:** A 1991 World Bank review of international power sales agreements found that in Northern America and in some developing countries, most cross-border contracts were executed in conjunction with an interconnector agreement. In Northern America, all contracts involved the creation of an operating committee. Functions varied, but could include:

- operation of the interconnection;
- metering, accounting and billing;
- coordination of maintenance;
- matching demand and capacity; and
- determining and allocating losses.

90. In only one of our case studies, NEPOOL, was all trade carried out within the framework of a multilateral contract, or pooling arrangement. The New England Power Pool Agreement runs to over 200 pages and provides a very detailed institutional framework for NEPOOL. Despite this, it is sufficiently flexible to allow very small municipal and very large investor-owned utilities to participate, and for membership across states with different power sector legislation. The Agreement itself contains only limited detail on operational procedures. There is, typically, a statement of what these procedures are intended to do, with the details of how this is to be achieved being left to the relevant committee. It is also important to note that this is a voluntary arrangement, and that members can leave on expiry of a given period of notice (although none have yet done so).

91. The business of running NEPOOL is divided into three functional areas:

- Operations - New England Power Exchange (NEPEX);
- Accounting and Settlement - NEPOOL Billing; and
- Planning (advisory only) - New England Power Planning (NEPLAN).

92. NEPOOL is governed by a Management Committee. Decisions require 75% support with less than 15% in opposition. The Management Committee appoints an Executive Committee to oversee the running of NEPOOL.

93. There are two further committees reporting to the Management Committee. The Operations Committee oversees system operations, accounting and settlement. Decisions are taken by a two-thirds majority. The Planning Committee evaluates expansion programmes, and makes recommendations to the Management Committee. The Management Committee recommendations to members are, however, advisory.

94. In all other case studies, the institutional framework was much less strong. Trade was principally regulated through contracts, with varying degrees of formality. In some cases there were also arrangements for technical coordination, discussed below.

95. In Southern Africa there is no formal regional coordination of electricity supply, and trade is undertaken within bilateral (or occasionally trilateral) contracts. However, in 1992, three of the SADC utilities (ZESA, BPC, ZESCO) formed an Integrated Operations and Planning Committee (IOPC) to coordinate power exchanges and plan operations. It is now intended to extend IOPC cooperation towards the creation of a SADC regional power pool, including RSA and Zaire.

96. The concept for the future is to develop the capability of the IOPC as a regional organisation for coordinating resource planning and load despatch, including the management of any joint facilities and the necessary measures for cost recovery and settlements. This type of arrangement, which falls short of full integration, is often defined as a "loose pool". Upgrading the IOPC in this way has the initial aim of maximizing the benefits of hydro/thermal operation, given the present ongoing drought situation.

97. Nordel has no formal powers and its members do not represent the governments of their respective countries. Organisationally, the Nordic pool is extremely loose. Trade has principally been based on bilateral, informal "gentleman's agreements". This has not prevented a reasonable volume of trade taking place. Trade in India is overseen by the Regional Electricity Boards, but is between two State Electricity Boards. Institutional arrangements are ad hoc, with trade not proceeding unless the operator of the interconnector receives confirmation from both parties on the power to be traded.

Bilateral or multilateral trade in economy energy is possible without specific government to government agreements. Governments may, however, play a greater role if trade involves pooling, and so restructuring of utilities which are mainly owned by governments; if there is firm power trade, and so an impact on security of supply; and if trade is of sufficient size to affect general economic planning, as in Laos and Zaire. Where pooling arrangements are set

in place, appropriate management structures will also be required. Voting rules can be set to ensure a high degree of consensus on the operation of the pool.

98. **Pricing principles:** The details of energy and capacity payments are discussed later in the report. In this section, we consider how far principles for price setting were agreed in the case study countries.

99. The principles on which trade was priced varied between countries. In India and (historically) in NORDEL, trade was priced on a split savings basis. The agreements covering this were relatively informal, and required a high degree of trust and information sharing between utilities. In India, they were based on a tariff set by a third party - the central Government generation corporations - and so were less dependent on revealing internal cost information. In NORDEL, they depended on accurate exchange of cost information for the trading parties' own plant.

100. In Southern Africa, there have been a variety of approaches to pricing. Arrangements have been made for pure energy trading. This requires that the participants demonstrate that they have sufficient capacity to meet demand. Energy trade is priced in relation to the displaced plant, for example 80% of the operating cost of a named plant. Firm power trades at a higher price, and typically reflects the desire to earn a specified return on generating assets at their replacement value.

101. NEPOOL operates on a split savings basis. Again, this is intended to be principally energy trade, since members are required to maintain capacity to meet demand. The savings are the difference between operating that capacity to meet members' own demand, and despatching plant in the pool on a least cost basis. This system requires confidence in the cost information, and this is reinforced by cost auditing. Because of these requirements for detailed audited information, operation of NEPOOL is intrusive and expensive. There are no capacity charges, but "free riding" on the pool is discouraged by penal energy charges when importers are found to be in capacity deficit.

102. Most case studies illustrated the need for an exchange of information as a basis for pricing. NORDEL provided an interesting example of how this approach could break down in response to power sector reform. With the deregulation of the Norwegian industry, Sweden, Norway's main trading partner, has refused to base payments on a mid-price formula calculated on the basis of the market prices in Norway. The argument has been that bids in the Norwegian pool are distorted above costs, and thus a mid-price between an inflated Norwegian market price and Swedish system marginal costs would favour the Norwegians. This has changed the way short-run exchange is organized between Norway and its trading partners. Now Swedish (as well as Danish) buyers and sellers bid into the Norwegian pool, and power exchange is regulated according to sales/purchases as determined by the pool merit order.

103. Following the change in the organization of trade, short-run exchange between Norway and Sweden has been lower in 1992 and 1993 than in previous years, but is expected to increase as participation in the market is extended further. In accordance with the pre-deregulation tradition, Swedish generators have tended to coordinate their bids through their main generator, Vattenfall, but gradually the various participants have begun submitting bids on an individual basis.

104. Although outside the case studies, it is of interest that a similar shift happened following the creation of the pool in England and Wales. Trade was carried out along two interconnectors, with Scotland and with France. Prior to privatization, this was on a split savings basis, with both parties declaring their marginal operating cost. After privatization, it was through the two generators in Scotland, and single generator in France, bidding into the English pool.

105. Prior to privatization, trading with Scotland was very low because the English generating board (CEGB) tended to understate its operating costs and overstate its transmission constraints. After privatization, trade with Scotland increased rapidly, which has led to roughly a doubling of the interconnector capacity. Trade with France has continued at high levels. However, it has become highly profitable for French exporters. Non-fossil fuel generators earn a premium in the English market (designed to cover the decommissioning costs of English nuclear plant), so French generation which is predominantly from nuclear sources benefits.

106. The discussion above illustrates a number of approaches to price setting. A related point is the importance of agreeing pricing principles and tariffs before investments proceed. This was not done in advance of the interconnection of the ZESA (Zimbabwe) and BPC (Botswana) grids, and led to difficult negotiations.

The case studies showed two broad approaches to pricing. One is to set a "fair" price, on the basis of avoided costs by one party or splitting the savings between both parties. The costs of such an approach grow 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 requirements for verification. There may also be shift to price setting on the basis of generator bids, as has happened for trade with Norway and with England. Irrespective of the approach, it is important to agree tariffs before investments proceed.

107. **Oversee and settle trade:** The case studies identified three ways of monitoring and settling trade:

- bilateral contracts;
- regulatory agencies; and
- pooling systems.

108. The sophistication of trading contracts will in part depend upon the ability to monitor trading arrangements. For example, the failure of SEBs to implement two-part tariffs and time of day pricing in India reflects the lack of comprehensive provision of meters with the necessary capabilities.

109. In NORDEL and Southern Africa, trade is undertaken under the framework of bilateral contracts, with varying degrees of formality. The two parties to that contract also agree how trade will be monitored and settled.

110. In NEPOOL, the settlement depends on theoretical despatch calculations. If the individual utility can come up with a lower cost despatch which observes all the constraints, that despatch is used. This event rarely happens. There is however, a good deal of trade in the secondary market. This affects the distribution of financial benefits, but does not alter despatch.

111. In India, trade is between two SEBs along an interconnector between two REBs. The trade takes place because one SEB has a contractual right to capacity at a centrally owned generating plant which it does not require. As the Regional Load Despatch Centres oversee the operation of central plant, they also oversee the trade. The cash settlement is between the SEBs on whose behalf the trade was arranged.

Metering can act as a constraint to trade, but one that can be removed at low cost. Different approaches to overseeing and settling trade have been used with apparent success.

112. **Agree and enforce technical standards:** Very different approaches are taken to the setting and enforcing of technical standards. In India, grid discipline has been a major problem within the synchronous REB networks: This has principally been due to capacity deficiency, and a reluctance of SEBs to shed load when their own generation, plus their contracted share of central plant, is insufficient. To avoid these problems, trade between REBs has all been on a radial basis, or through DC lines.

113. In Southern Africa, the proposed control strategy is that each participating utility of an interconnected system should act as a Control Area Operator. This is the standard control method for large interconnections, and does not assign frequency control to any one area. In this respect, the importance of, and degree of load following, is not an individual choice. Uniformity of control must be maintained throughout the interconnected systems in order to avoid chaotic unbalances and ultimate system collapse.

114. NORDEL's remit includes the technical coordination of the Nordic power generation and transmission systems. It thus puts in place arrangements for frequency stabilization, power exchange etc.

115. The North American Electricity Reliability Council (NERC) was set up in 1967, partly in response to earlier black-outs in New York and the New England states. Nine regional reliability councils agree on reliability criteria and check on the application of those criteria. These bodies are organised according to the principal electricity networks, and accordingly three of them cross the border between the USA and Canada. This includes the North East Power Coordinating Committee, within which NEPOOL lies. NEPOOL members have to agree technical standards on a wide range of issues, including cost audit methods, efficiency measuring, reserve, transmission outage criteria etc.

The principal conclusion is that 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 widescale AC interconnection.

Contract enforcement

116. Trade will not develop if contracts cannot be enforced, ensuring reliable payment. Difficulties in contract enforcement can be reduced through drawing up carefully designed contracts, through institutional frameworks for resolving conflict, and through arbitration procedures.

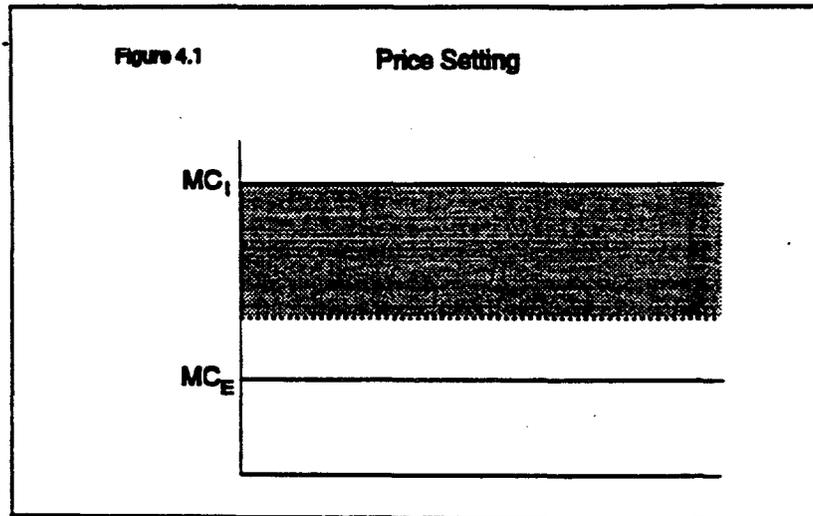
117. India provides the main example of difficulties in contract enforcement. There are examples of payment for trade between SEBs being delayed for up to one year. No specific examples were quoted of difficulties in enforcing contracts between REBs. As there is no synchronous connection, it would of course be straightforward to stop trade if payment was not forthcoming. Inter-REB trade does not suffer from the same grid discipline problems as trade within REBs.

Contract enforcement may be a problem for some countries and power sectors. Problems are likely to be greatest for trade within synchronous networks.

Pricing issues

118. Contracts cover the supply of energy and transmission services. They can be short term, affecting despatch decisions by the purchaser, or long term and also affect investment decisions. If they are incorrectly structured, they will not give incentives for optimal despatch and investment.

119. The potential for trade will exist where there is a cost differential in bulk electricity supply to the importing country. This is illustrated in Figure 4.1 below. The marginal cost of the exporting country is shown by the lower line (MC_E) and its delivered cost (after allowing for transmission) by the dotted line. The marginal cost of the importing country is shown by the higher line (MC_I).



120. Trade is possible where price is between the exporter's incremental cost, and the importer's avoided cost. This is illustrated by the shaded area. The location of price within that shaded area will determine the allocation of the benefits of trade between the exporting and importing countries.

121. The diagram can refer to both short and long term trade. In the former case the relevant cost will be the short run marginal cost (SRMC) of the marginal plant within the two systems. This raises the possibility of major cost differentials, for example, between run of river or spill hydro and displaced thermal plant. In the latter case the relevant cost will be the long run marginal cost (LRMC) faced by the two systems.

122. **Energy charges:** Short term despatch decisions will be optimised if they are based on the short run marginal cost (SRMC) of all eligible plant. In India, SEBs have to decide whether to despatch their own plant, their share of centrally owned plant or (when available) whether to import. Historically, the price for energy from centrally owned plant reflected both SRMC and fixed capacity costs. SEBs correctly treated their own capacity costs as sunk when making despatch decisions, but faced prices that indicated that centrally owned capacity costs were not sunk. As a result, they tended to under-use centrally owned plant.

123. The central sector National Thermal Power Corporation (NTPC) has now introduced a two-part tariff for its plant. The despatch decision can be based upon the energy charge, structured to reflect SRMC. However, because of metering deficiencies between SEBs, only energy flows over a period can be measured. This means that trade between REBs is still conducted on the basis of average prices for centrally owned plant in the two REBs, including both capacity and energy charges. This, in turn, means that imports along an interconnector are not priced on the same basis as SEB plant. Again, there are incentives to under-use electricity trade when comparing prices for despatching different plant.

124. In Southern Africa, agreements typically distinguish between firm and surplus energy. In order to pay for surplus energy, purchasers have to demonstrate that they have sufficient capacity available to meet demand, or that they could meet demand from other firm power contracts without exceeding interconnection capacity.

125. Surplus energy imports are usually priced in relation to avoided cost. For example, the importer might pay 80% of the SRMC of a named power station. In such cases, the calculation of the SRMC has to be provided and agreed on an annual basis.

126. Provided the marginal plant is correctly identified and its SRMC correctly calculated, this will encourage optimal despatch. The energy price will affect the distribution of the gains from trade. If the energy price is a high proportion of the avoided cost, a high proportion of the gains will accrue to the supplier. The lower the proportion of avoided cost, the greater the share of gains held by the importer. If the proportion falls too low, however, payments might fall below the SRMC of the exporting plant, and prevent electricity trade proceeding.

127. In NEPOOL, despatch decisions are made by NEPEX on the basis of audited declarations of SRMC. Plant despatched is paid its SRMC. The gains from this trade are included in the NEPOOL savings fund, which is distributed according to the volume of trade each member conducts with the pool.

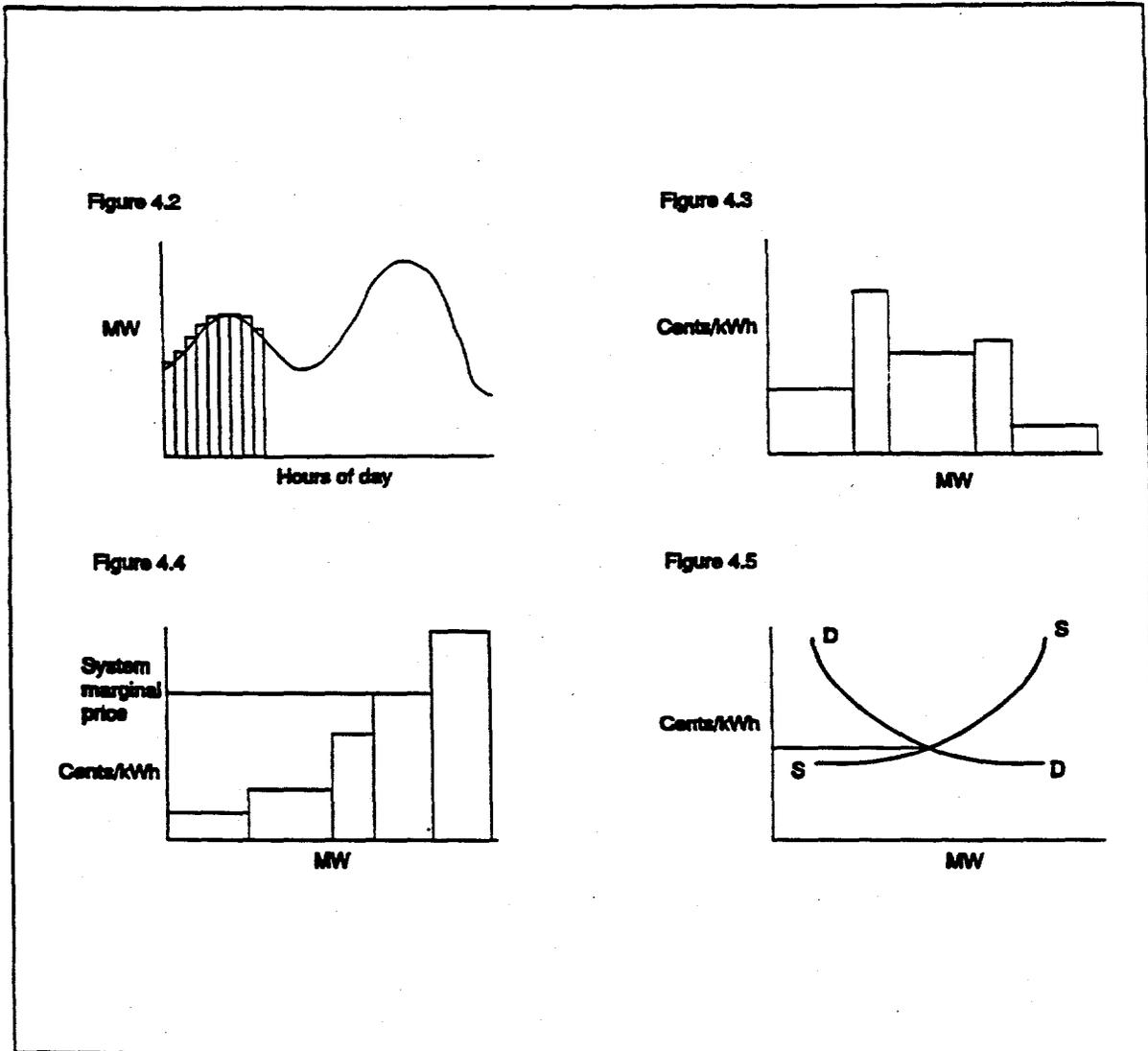
128. In both these examples, the aim is to give the correct incentives for despatch and to agree how the gains from trade will be shared. They differ in how frequently messages are revised on the marginal cost of imported energy, and in what information is required to verify costs.

129. NORDEL has traditionally operated trade on a "split savings" basis, with cost information being shared between utilities. Since power sector reform in Norway, this has broken down. Utilities trading with Norway no longer trust prices in the Norwegian pool to reflect SRMC. This is a reasonable assumption. There is strong evidence that the main generators have colluded to increase prices in the pool. As a result, trade with Norway is now conducted through bidding into the pool by generators or purchasers of bulk energy.

130. The mechanics of a bidding process are illustrated in Figures 4.2 to 4.5. The first requirement is to determine what volume of energy is required. This is done (by the pooling company in Norway) for short time periods throughout the day. Figure 4.2 shows a daily load curve broken up into half hour intervals, for each of which separate bids will be sought.

131. It is then necessary to select bids from generators to ensure that demand is met and costs are minimised. Bids will be for different volumes of energy, and at different prices, as shown in Figure 4.3. These can then be ranked by price to prepare a cumulative supply curve, as shown in Figure 4.4. Generators' bids will be accepted until the required volume of energy is obtained. This supply curve will be identical to that which would have been built up through least cost despatch, provided competition is effective in ensuring that bids reflect generators operating costs.

132. The bid price of the last generator accepted is known as the system marginal price. Generators bidding above this price are not taken. The basis for payment can vary between pools, but in Norway, all generators taken are paid the system marginal price.



133. The structure described above is similar to that used in the pool in England and Wales. A further sophistication of the pool in Norway is that major consumers (including a number of energy-intensive industries that are price sensitive) are able to bid in their demand curves. The market clearing price is then set by the interaction of the supply and demand curves. The three approaches to setting energy charges described above can all lead to prices that give incentives for economic trade to proceed, that is within the shaded area in Figure 4.1. They differ in two respects. The first is the allocation of benefits. Approaches such as split savings were developed in part because they were seen as a "fair" division of benefits. A bidding system is likely to lead to a much higher share of the benefits being retained by the exporter.

134. The second difference is in transaction costs. Split savings contracts may be relatively complex, and demand information on the marginal cost of plant within two systems. This information needs to be periodically updated and verified. Where this approach has been used between two publicly owned utilities, they have frequently been able to implement it at relatively low cost, reflecting either a greater degree of trust between the utilities or lower incentives for minimisation of financial cost. Use of split savings when one or more private utilities are trading is likely to require substantial cost auditing, increasing the transaction costs of this approach. A bidding system requires (and equally provides) no information on the marginal costs of plant, and so has a lower transaction cost.

135. **Capacity payments:** Long term firm supply contracts provide a higher benefit to the purchaser. They either allow load to be served that is currently going unserved, or allow investments in new capacity to be postponed. As a result, firm long term contracts attract a higher price.

136. NEPOOL is an exchange for energy. It is founded on the understanding that members provide themselves with enough capacity to meet their demand with the reliability agreed with the pool. Members can provide the capacity through building their own plant, participating in shared plant, or contracting with other members or IPPs for capacity. Members failing to meet the capacity requirements will be charged penal rates for imports, where such imports are due to capacity deficit.

137. A number of the trading agreements in Southern Africa distinguish between firm power and surplus energy. Firm power is specified in terms of MW, is to be supplied at a unitary load factor (although in some cases acceptable minor variations up and down are also set out), and is to be supplied for the contract life. In some cases, the lifetime of firm power agreements is set by the commissioning of new capacity under construction in the importing country.

138. Two approaches are taken to charging for firm power. One is to set a charge, but to reduce this pro-rata if there is a failure to supply all the power stipulated in the contract. This cannot be regarded as a firm power contract. As there is no penalty for failing to supply the power, the supplier has very weak incentives to ensure capacity is available. The alternative approach is to require the purchaser to take the power, through a take or pay contract. Again, agreements of this kind do not appear to set out penalties for non-supply. Charges are typically set in US\$ and escalated at an agreed rate (often 6%), rather than related to some agreed measure of US inflation.

139. The existing and proposed hydro stations based in Laos for export to Thailand provide firm power. EGAT, importing to Thailand, is seeking to negotiate firm power agreements for the next 1500 MW hydro plant. This would require the plant to provide a specified level of firm power at all times, and would price that firm power at the cost of displaced (baseload) capacity.

140. **Transmission pricing:** Different spatial configurations of generation and load will affect costs through their impact on transmission losses; transmission constraints, and so the need to run plant out of merit; and the probability of outage. Efficient transmission pricing should reflect these variable costs.

141. The owners of transmission networks also need to recover their fixed or infrastructure costs. The basic objective in allocating network infrastructure costs should be to minimise the distortions to short run pricing signals. For example, transmission pricing that passes on capacity charges on the basis of capacity will be less distortionary than one that charges for infrastructure on the basis of system use. In the latter case, the networks will be under-used, since there is a perception that marginal use incurs an infrastructure cost, when in fact these costs are already sunk.

142. Transmission typically accounts for around 10% of final energy costs in a mature system. These costs will be higher for systems with relatively peaky loads; with a low density of load; or with generation located a long way from load centres. All these aspects are more typical of utilities in developing than developed countries.

143. While the contribution to final prices is relatively small, the impact on trade will be much greater. Trade may be based on relatively small differentials in bulk supply costs between different locations. Transmission costs can therefore significantly affect decisions on trade.

144. Transmission pricing is less sophisticated around the world than bulk supply or retail pricing. Relatively few countries have developed sophisticated pricing systems that give accurate locational messages to generators and consumers. This was also the case in our developing country case studies.

145. In India, the PowerGrid corporation has only recently been formed, and is paid contract fees for wheeling central sector generation to SEBs. Consultants are currently looking at a more cost reflective charging system for PowerGrid. One of the aims is to encourage IPPs.

146. Many of the trading arrangements in Southern Africa do not explicitly incorporate transmission charges. These will usually be incorporated into the sale price, where sale is from one vertically integrated utility to another, neighbouring vertically integrated utility.

147. Transmission charges are unbundled from the price where they represent costs incurred by a third party for wheeling power. Wheeling charges in Southern Africa incorporate the following components:

- connections. The capital component can be met through an annual contribution to the depreciation of the line. This has the advantage that if the line ceases to be dedicated, for example if other consumers along the route make use it, the costs can then be shared among all beneficiaries;
- a charge for use of existing infrastructure. This charge is set pro-rata to the volume of energy being wheeled. As such, it gives an inappropriate signal on short-run costs; and
- a charge for losses incurred through wheeling, again a flat rate percentage of the energy wheeled. This approach to short run pricing is appropriate, although the actual measures used are relatively crude. They are based on a single estimate of incremental losses, which in practice are likely to vary, and do not explicitly reflect the other short run costs discussed above.

148. Transmission pricing in the NORDEL region is typically set by the operator of the transmission network, which in some, but not all, cases remains in public ownership. Approaches to transmission pricing vary. There are recent examples of inefficient wheeling investments, and in particular Norway's failure to agree wheeling charges with Sweden that would enable it to transfer power from the North without expanding domestic transmission capacity.

149. Transmission in NEPOOL is the responsibility of member utilities. Where transmission is planned by NEPOOL, it is paid for by all members on the basis of maximum demand.

Approaches to energy, capacity and transmission pricing varied. Problems on energy pricing arose mostly in transition from one pricing 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 our case studies transmission was not unbundled or separately priced. This did not appear to be a constraint to trade. If power sector reform proceeds, then access to transmission networks and transmission pricing could become constraints to trade.

150. **Interconnector pricing:** The pricing of interconnector capacity can be viewed as a subset of transmission pricing. In most of our case studies capacity of interconnections across borders was more constrained than transmission capacity in general. The usual solution to this problem where there was more than one generator wanting access to the interconnector was to allocate interconnector capacity.

151. The UK provides an example of the impact of power sector reform on interconnector access. Following the privatization of electricity in Scotland, the two private utilities retained indefinite contractual rights to (almost all) the interconnector to England. They can sell this capacity to each other if it is not required during a particular period. They are also required to quote a price to third parties who want access to the interconnector. It seems unlikely that they would quote an acceptable price, and so setting charges for interconnector capacity may require regulatory intervention.

Imbalance of risk

152. Firm power trade creates substantial commercial risks for both parties. If a plant is built for export, the exporter faces a risk of "hold-up" after the plant is built. A dedicated plant has no other use. The importer may seek to renegotiate contracts that reduce payment to a level closer to the marginal operating cost of the plant. At the same time the importing country may seek to ensure security of supply through setting penalties for failure to meet contractual commitments. Enforcing penalty charges may be difficult.

153. There is evidence from the case studies of trade that has not proceeded because of the perception of risks. A good example is the failure to develop hydro resources in Nepal for export to India. There are also examples of explicit policies of ensuring security of supply from domestic capacity.

154. Two responses are possible. On the principle that risk should be allocated to whoever is best able to manage it, one solution is foreign ownership of the generating plant. This is being pursued to some extent in Laos, where private Thai and South East Asian investors may be financing future generation investment. EGAT itself, which will be the purchaser of the energy, is not proposing to finance investment.

155. Solutions that involve foreign ownership may not be politically acceptable. They are often associated with requests to safeguard investments - and perhaps the transmission lines associated with them - that may raise security issues in the country concerned.

156. A second alternative is to make contracts more binding by placing an appropriate sum in bond. The sum can be drawn down if either party fails to meet its contractual obligations. This decision is taken by an agreed independent third party. This is similar to financing mechanisms that have been used by international financial institutions to try to reduce the risks for private power generators.

Technical problems

157. Technical problems were of greatest importance in case studies where there were weak links between relatively developed grids. This was the case, for example, in Southern Africa, India, and South East Asia. Descriptions of the specific technical issues that arose are given in the case study reports (Annexes). This section summarises the principal technical issues covering the interconnection of power systems.

158. **AC links:** In AC power systems, all the generators connected to the system operate at the same electrical frequency and in synchronism. All the generating sets are equipped with a governor which is a control mechanism designed to keep the turbine operating at a constant speed (and hence frequency). As the turbine slows down through the imposition of more load, the governor senses the drop in speed and increases the steam (or, in the case of hydro-electric plant, the water) supply. Thus, provided enough generators are connected to the network, supply and demand are in balance.

159. When two systems are not interconnected, they may run at different frequencies and will not be in synchronism. If they are connected by an AC interconnector, power will flow through the connector to make the frequencies of the two systems identical. If the frequency of one is markedly lower than the other, a large amount of power will flow into the slower system. If the connection is a relatively weak one, that is its load carrying capability is small compared with the size of the two systems it is interconnecting, the amount of power it is required to carry to bring the two systems into synchronism may exceed its carrying capacity. In this case, the systems will break synchronism, and electrical instability will result. The link will be broken, and one or both of the systems may suffer electrical collapse. Very close control of the outputs of the power stations in the two networks can overcome this problem.

160. **DC links:** In DC links, AC power is rectified into DC, and is transferred across the link as DC and then converted back to AC through an inverter station. The transfer of power is controlled by the electronics of the converter station and takes place independently of the frequency of either AC system. This means that controlled quantities of power can flow between two asynchronous AC systems with no need to apply tighter control to the internal workings of either.

161. The converter stations are expensive, but DC lines are cheaper than AC lines per MW kilometre of transmission capability. Thus a long distance DC line might be cheaper than equivalent AC line, but for short distances DC will be considerably more expensive. In India very short-back-to-back DC links are under construction to enable power to be transferred between adjacent regions without the need to synchronise.

162. Whilst DC links do allow the transfer of power between regions without the need to synchronise, this very fact reduces their usefulness for providing mutual spinning reserve. This is because the link is incapable of responding to the frequency changes resulting from a sudden generator loss incident in one of the networks. The table below summarises the relative characteristics of DC and AC links. DC links can be provided with control electronics to make the flows respond to frequency, but this would reduce the operational independence of the connected networks.

Relative Merits of AC and DC Interconnections		
Parameter	AC	DC
Control	Tight load and frequency control <u>required</u> in interconnected networks. Operating cost implications	Link power flow is set electronically and <u>can be</u> independent of conditions in either interconnected network
Frequency	Requires synchronism	Allows independent operation
Spinning reserve	Automatically supports deficient area, within capability of link. Sudden changes in generation condition could trip link (if relatively weak) and risk collapse in one or both grids	Can be programmed into control electronics if desired. Self limiting therefore less risk of grid collapse
Voltage control and reactive power	Can be transferred. Needs careful control in both networks	Cannot be transferred. Converter stations require reactive power for excitation
Capital and operating cost	Cheaper for all but the longest connections. Modest losses	Converter stations expensive, lines cheap. Can be cheapest option for very long distances. Relatively high maintenance. Modest losses
Reliability	Very high	High, can be improved by use of bi-polar links

Impact of Power Sector Reform

163. Power sector reform can encompass:

- commercialisation and corporatisation of the power sector;
- unbundling of generation, transmission and distribution; and

- introduction of private capital, whether through sale of assets or private financing of new capacity.

164. While power sector reform was under consideration in a number of case studies; NORDEL was the region where there had been the greatest recent changes. Because of the lack of case study evidence, our comments on the impact of power sector reform are more tentative, and less directly drawn from the case studies, than other elements of this report.

165. A common feature of recent reform is to increase competition where possible. As transmission and distribution are natural monopolies, this principally applies to generation, although supply businesses can also be competitive. In Norway generation is principally on the basis of long term contracts, although there is a competitive wholesale pool that covers up to 10% of energy sold.

166. The pool was originally only open to generators, and allowed them to meet their long term contracts more cheaply through trading with other generators. Recently it has also been opened to consumers and to traders. Danish and Swedish suppliers can bid into the pool, and will be selected if they are the cheapest.

167. The immediate impact of the above described reform, was to disrupt the agreed pricing mechanism and - possibly - to contribute to a fall in energy trade. However, it should be pointed out that the reform altered the balance of power in the sector and that this may assist trade. Danish, Swedish and Norwegian generators bidding into the pool have an equal interest in ensuring that pool rules are fair and are enforced.

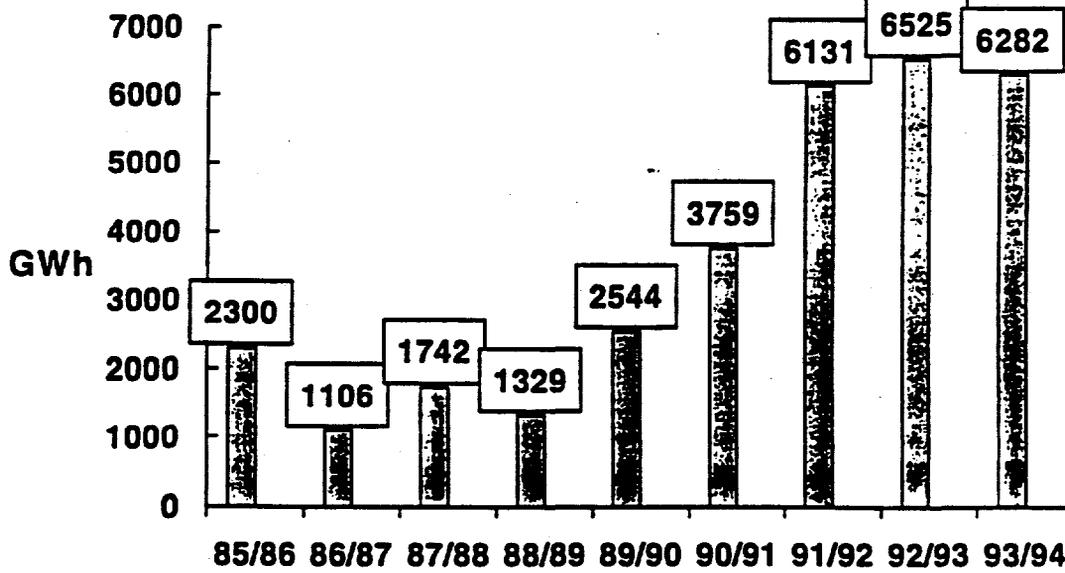
168. Power sector reform may also involve corporatisation, with increased efficiency incentives, or transfer of ownership to profit maximizing private companies. In Southern Africa there is interest in private financing of new capacity investment, and some Indian SEBs are also looking at privatization of existing assets.

169. This should have a number of positive effects on the development of regional networks. Incentives for cost minimisation are increased, and costs become more transparent. The private sector is more familiar with assessing and managing risk, and is generally more risk averse. As a result, it may take a different view of the risks associated with trade, or introduce ways of managing those risks.

170. An example of the longer term impact of power sector reform on electricity trade is shown in Figure 5.1. The figure shows annual metered flows along the interconnector between Scotland and England. These consist almost entirely of exports from Scotland. Prior to power sector reform trade was on a split savings basis. English generators tended to understate their costs leading to sub-optimal exports.

Figure 5.1

Electricity Trade Between Scotland and England



171. Reform led to a near trebling of trade, without any change in transmission capacity. This increase started in 1990/91, as liberalisation was set in place (although note, the 1990/91 metered flow is an estimated figure), and has grown rapidly since resting in April 1994.

172. Transmission tends to be retained by the public sector, and in some cases remains associated with the dominant public generator. This has been the case in a number of the Nordic countries. Third party access, and appropriate pricing of transmission, may be relatively slow to develop. If transmission remains associated with some generators, the transmission company will have incentives to compare its own generators avoided (short term) cost with bids from other generators that include returns on capacity.

173. In contrast to the incentive effects identified above, there are a number of institutional arguments which suggest regional power networks are more easily established under public ownership - possibly because transactions costs will be lower. A priori it is not clear that incentive effects will dominate. Gegax and Tschirhart (1984), for example, find statistical evidence that publicly owned utilities in the US are most likely to be in pools, other things being equal.

174. Structures for regional coordination sometimes already exist between governments. Among developing countries, SADC is perhaps the best example. Publicly owned utilities are drawn into this cooperative framework by virtue of its inter-governmental nature. This may make the establishment of interconnection more straightforward utilising existing negotiating structures, although it has not prevented bitter disputes on the arrangements for electricity trade.

175. If restructuring leads to utilities becoming potential competitors, the incentive to declare actual costs for despatching purposes and to share information more generally is reduced. This was reflected in the breakdown of agreed pricing principles, following power sector reform in Norway.

176. Where power sector reform brings unbundling (vertical disaggregation), the need to coordinate power transfers among a larger set of firms may raise the transactions costs associated with interconnection. Moreover, if managerial capacity within the industry is limited to begin with, it will be further diluted by unbundling. Our developing country case studies have not, however, pursued unbundling.

Our conclusion is that power sector reform may increase the transaction costs of electricity trade, but should provide greater incentives. Transaction costs are slight when set against the gains from trade, and power sector reform is likely to lead to greater trade. It may well, however, introduce transitional problems, due to the movement from an established trading regime to a new one.

Impact of Environmental Issues

177. There are two main environmental changes as a result of greater trade. One is the change in generation and the second is the greater use of high voltage transmission lines.

178. The main pollutants associated with operating generation plant are sulphur and nitrous oxides, carbon dioxide, waste heat, and ash from coal-fired plant. The impact of trade should be to use generation more efficiently. In all cases we examined, this included some substitution of thermal plant by hydroelectricity. Trade therefore reduces total pollution, but may exacerbate local pollution problems. Trade may also allow more active environmental intervention. For example, the European Commission's 1993 amendment to the Transmission Directive allowed system operators to discriminate in favour of renewable energy and combined heat and power sources.

179. NORDEL publishes estimates of the environmental savings due to trade, compared with each country being self-sufficient in energy. In 1992, trade reduced emissions of pollutants by 29,000 tons SO₂, 32,000 tons NO_x, 16 million tons CO₂ and 380,000 tons of ashes. Even though the overall benefits are substantial, there are indications that further gains are possible if trade in energy is increased.

180. The efficiency of fuel use increases as a result of trading. If trade acts to reduce the unserved energy, and hence increase the total amount of generation from thermal plant, then emissions of pollutants increase.

181. This was the case in India where detailed analysis was available. Indian coal has a very high ash content, and ash disposal is a significant consideration.

182. The table below sets out India's changes in emissions of the principal pollutants resulting from increased trade between Northern, Western and Southern regions. The figures are drawn from the London Economics' report *Long Term Issues in the Power Sector 1991*, and apply to the year 1989/90.

183. Ultimately, when the system in India moves away from the chronic plant shortage, trading the increased efficiency should lead to reduced emissions as a result of trading.

184. Construction of new generation plant also creates environmental impacts. The case studies provided little information on this, since much of the trade was for economy energy, and did not affect investment decisions. Thailand may provide one example of a country where environmental pressures make it increasingly difficult to proceed with hydro investments. Thus electricity trade can be seen as one way of "exporting" environmental problems.

185. There is also increasing resistance to high voltage transmission lines on environmental grounds. This has been of greatest significance in developed economies. Within the UCPTE network, there are a number of recent examples of economic cross-border 400 kV links that have not proceeded, because of environmental concerns.

Changes in Emissions, Relative to Base Case, for Different Trading Volumes (Thousand Tonnes)				
Pollutant	Ash	SO₂	NO_x	CO₂
Inter regional trading to existing tie line capacity	572	22	23	5,387
Unconstrained trading ⁴	572	27	30	7,598

⁴ ie. assuming all transmission constraints are lifted.

ANNEXES

EXAMPLES OF REGIONAL ELECTRIC POWER NETWORKS

ANNEX 1 ● Southern Africa

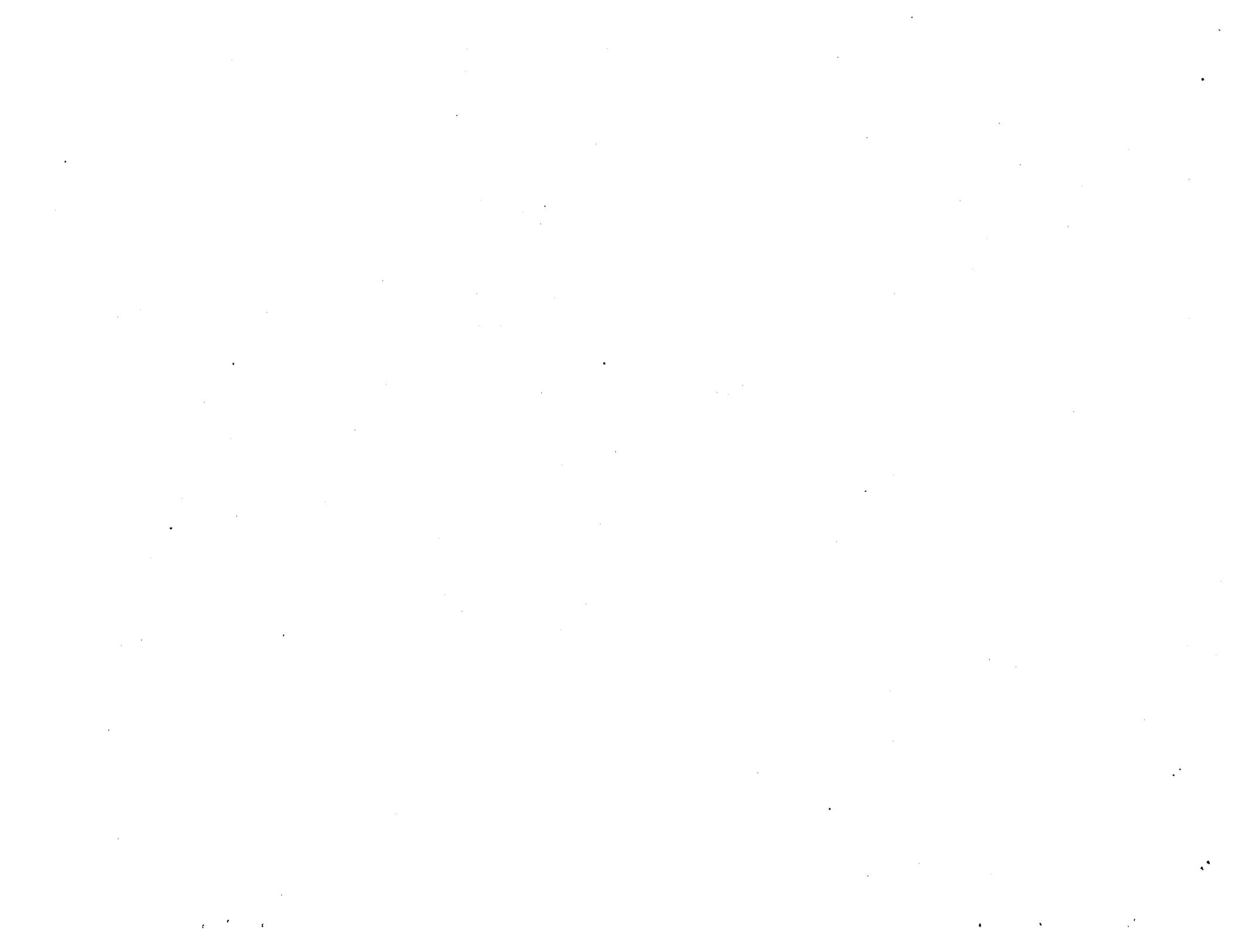
ANNEX 2 ● India

ANNEX 3 ● NORDEL

ANNEX 4 ● South East Asia

ANNEX 5 ● NEPOOL

ANNEX 6 ● MAPP



Southern Africa*

Introduction

1. There are several well established power systems in the region, providing bilateral and tripartite electrical trade, although a formal pool has not yet been formed. These networks are interconnected at 220 kV and 330 kV from the Shabah Province in Zaire through Zambia, Zimbabwe and Botswana, as shown by the regional transmission map of Figure 1.1. The interconnections are completed with a 132 kV link between Gaborone in Botswana and Spitskop in the Transvaal of South Africa (RSA). Thus, Southern Africa already has bulk transmission interconnections from the equator to the Transvaal, soon to be reinforced with a 400 kV link between Matimba (in RSA) and Bulawayo (in Zimbabwe). When completed, this link will initially enable surplus RSA thermal power to be made available to offset reduced hydro generation due to drought in the SADC countries, and later allow imports to RSA.

International agreements

2. International power agreements have been in existence in the region since at least the early 1950s, when the 220 kV Zaire-Zambia interconnector supplied surplus hydro-power from Shabah Province to the Zambian Copperbelt. The Kariba link between Zambia and Zimbabwe was also built in 1960 before the separation of Rhodesia into two independent States. In more recent years network interconnections and associated exchange agreements have multiplied, mostly because of Southern African Development Community (SADC) efforts and encouragement by international aid donors. The level of international annual electricity exchange in the region is doubling about every five years, or at an annual average rate (AAR) of 15%. This is forecast to be of the order of 1000 MW (or 7500 GWh/a) in 1995/96 and worth approximately US\$125 million per annum.

3. Within the whole of Central and Southern Africa there are at least 16 major international power exchange agreements in force or about to be instituted, as given in Table 1.2 (p.26). However, the main agreements are those that form the interconnection "backbone", between Zaire and RSA through Zambia, Zimbabwe and Botswana; a transmission distance from Inga to Matimba of about 5000 km. The agreements are between "parastatal" utilities in each Country, viz.:

* This case study has been investigated by Peter Lewis, Engineering & Power Development Consultants (EPD)

- SNEL: Societe National d'Electricite du Zaire
- ZESCO: Zambia Electricity Supply Corporation
- ZESA: Zimbabwe Electricity Supply Authority
- BPC: Botswana Power Corporation
- ESKOM: Electricity Supply Commission (of RSA)

4. The above utilities are all vertically integrated, with generation transmission and distribution facilities under common ownership. Furthermore, the electrical power industry is government controlled and highly centralised.

Pooling arrangements

5. Although there is yet no formal regional co-ordination of electricity supply, in 1992 the three SADC utilities (ZESA, BPC, ZESCO) formed an-Integrated Operations and Planning Committee (IOPC). This Committee was convened to co-ordinate power exchanges and plan operations following the completion of the 220 kV Bulawayo-Francistown line and the wheeling of power between ZESCO and BPC over the ZESA network. It is now intended to extend IOPC co-operation towards the creation of a SADC regional power pool, including RSA and Zaire, with the building of the 400 kV Matimba-Bulawayo line.

6. The present concept is to develop the capability of the IOPC as a regional organisation for co-ordinating resource planning and load despatch, including the management of any joint facilities and the necessary measures for cost recovery and settlements. This type of arrangement, which falls short of full integration, is often defined as a "loose pool". Upgrading the IOPC in this way has the initial aim of maximising the benefits of hydro/thermal operation, given the present ongoing drought situation.

7. Lower water inflows into the region's major hydro reservoirs have reduced energy output, and this reduction could be sustained for a decade within a longer term cycle (>30yrs). Energy balances must be made up and it is thus proposed to urgently utilise surplus thermal generation plant in RSA by the building of the 400 kV Matimba-Bulawayo line.

8. The immediate benefit of the Matimba-Bulawayo line will be to enable some of RSA's existing surplus thermal power, currently estimated at 8000 MW, to make-up the hydro deficiency. This new line is to be routed via Selebi Pikwe (in Botswana) and interconnected to the Botswana network. This will complete the southern section of the regional bulk transmission corridor, as endorsed in Phase II of the SADC Energy Project AAA3.8, which evaluated alternative power development scenarios. It should be noted that these scenarios envisaged power wheeling ultimately in both directions through the corridor, which might then require reinforcement.

9. The AAA3.8 scenarios were evaluated on the basis that a formal pool would be formed: defined as a loose pool with a central co-ordinating administration. It was thus envisaged that with a formal pool arrangement instituted between utilities, some or all of future investment and operating activities would be fully co-ordinated. In AAA3.8 it was expected that progress towards a formal or "tight" pool would be implemented in successive stage-wise co-operative arrangements over a number of years, towards full regional integration of electricity supply. It is now understood that new Terms of Reference are being prepared for the expanded IOPC in order to expedite this Southern African Power Pool (SAPP) objective.

Economic and political considerations

10. Almost a third of all Africans or 40 percent of the population of sub-Saharan Africa (210m) live south of the equator. It is also noteworthy that sub-equatorial Africa includes Angola, South Africa, Zaire, Zambia and Zimbabwe which collectively account for the bulk of sub-Saharan Africa's mineral and hydrological resources. However, most of the minerals (including coal) are found in the south of the sub-continent, with the hydro catchments mainly close to the equator. The Congo (Zaire) river alone has an exploitable capability of 530,000 million kWh/annum. Fossil energy resources also abound, and it is estimated that a 5 percent energy growth rate would consume only a small fraction of the known oil, gas, coal, geothermal, and hydro resources.

11. There are twelve sub-equatorial countries, ten of which belong to the Southern African Development Community (SADC); an economic union formed in 1980. The SADC countries are Angola, Botswana, Lesotho, Malawi, Mozambique, Namibia, Swaziland, Tanzania, Zambia and Zimbabwe. The two countries outside SADC are Zaire and RSA, but it is understood that membership is under discussion and that the enlarged grouping could also include Kenya and Uganda. In this respect it should be noted that at the 1992 Maputo Conference SADC announced its intention to form a fully integrated common market some time after the year 2000.

12. SADC was originally formed with the politically-motivated aim of reducing its members economic dependence on South Africa as one of its principal objectives. Despite this political polarisation, a pragmatic approach to regional economic relations prevailed. Furthermore, within the limitations of its institutional framework, SADC's achievements in developing a regional identity are considerable. For example, SADC has provided a valuable role in negotiations for external development assistance for projects involving or affecting more than one member-state. It has assisted the various donor agencies in identifying and ranking priority projects, and provided recipient countries with an enhanced capacity to articulate needs, thereby contributing to more rational and co-ordinated aid disbursements to the region.

13. The latest statistics for the region show that the ten SADC countries collectively had a total GNP in 1989 of US\$25 billion, whereas the GNP for RSA was US\$86 billion. The corresponding population statistics were 84 million and 38 million respectively to give SADC a per capita GNP of US\$307 compared to US\$2460 for RSA. From these statistics it is evident that the combined GNP/capita for southern Africa, including RSA, is three times that for the SADC region alone. This demonstrates the dominant role of the RSA economy that cannot be ignored in any serious study of southern Africa.

14. Over the last two decades the economies of most SADC countries have declined significantly, following the trend in sub-Saharan Africa, and this has resulted in serious foreign exchange shortages. The World Bank/IMF have instituted Economic Structural Adjustment Programs (ESAPs) in an attempt to stabilise the economies, and there is some evidence that the economies are now bottoming out. However, in most SADC countries real GNP growth in local currency has failed to keep up with population growth rates, resulting in a decreasing trend in GNP/capita. Other economic problems are excessive debt burdens, instability and high inflation rates. Debt is a very serious problem hitherto aggravated by tight exchange controls, and forms a discouragement to further foreign investment.

Power systems and interconnectors

15. This section begins with a network overview and history of interconnection in the region. The latter to a large extent mirrors power system development and the exploitation of the region's mineral wealth in the colonial period. This overview includes a country-by-country review of the present power sector status in the region, based on information obtained during the field trip together with scrutiny of available reports.

16. The basis and capability to trade energy is then discussed together with commercial arrangements and existing contracts between the main countries, viz.: Zaire, Zambia, Zimbabwe, Botswana and South Africa (RSA), as their networks are interconnected and thus already form a regional grid network. Other bulk power agreements, included in Table 1.2, while also important are excluded from discussion, as they are unlikely to affect the main grid "backbone" of the region.

17. To complete the section, prevailing attitudes to institutional reform are presented and especially perceptions on the role of the private sector in future power development.

Regional power overview

18. In most countries in the region, internal networks serve to distribute power from central power plants to the major load centres. Voltages correspond to the load transfers involved and to the distances to which the power is to be transmitted. In most cases, voltage levels are at 330 kV, 220 kV and 132 kV. There are two major HVDC transmission lines in the region, built in conjunction with large hydroplants and basically for power export to neighbouring countries.

19. The two HVDC lines are both rated at ± 533 kV and export surplus power from Inga II in Zaire (1424 MW) and Cahora Bassa in Mozambique (2075 MW). The Inga line terminates at Kolwesi in the Shaba Province (of Zaire) and a 220 kV circuit interconnects with Luano in Zambia. The Cahora Bassa line runs from Apollo in RSA to Songo in Mozambique, but is presently not in operation as a result of sabotage during the insurgency in Mozambique.

20. Zaire, at the equator, has just 2600 MW of hydropower developed, mostly due to the Inga complex (1750 MW), which is connected to the southern (Shaba) province via a 1700 km ± 533 kV HVDC line, built in 1983 to link the western and southern systems. At present Zaire supplies electricity to border towns in Angola and is connected to Zambia via the Shaba 220 kV grid. Zaire's actual and potential hydropower resources are estimated at close to 530,000 GWh. At Inga alone there are plans to develop a further 40,000 MW (the Grand Inga Scheme) which it is estimated could produce 320,000 GWh per annum. Zaire could be a major supplier of power to its neighbours in all directions, and there is a proposal to deliver power also to Europe via Morocco and Egypt.

21. Zambia and Zimbabwe have an integrated hydro/thermal power system with a combined capacity of about 4000 MW. This system was originally conceived as a unitary network in 1956. The primary motivation was the Kariba Hydro-electric Scheme, designed to supply power to the copper mines in northern Zambia, and to the industrial belt of central Zimbabwe. The load centres prior to Kariba all had local thermal generation, and the copperbelt was supplied by a 220 kV interconnector with Zaire, exploiting the hydro resources of the Shaba Province.

22. All present hydro developments are on the Zambezi River or its tributaries, mostly at Kariba and Kafue Gorge. Downstream on the Zambesi, in Mozambique, the 2075 MW Cahora Bassa south bank hydro-plant was also developed, but currently is not in operation, awaiting reinstatement of the HVDC line to South Africa. This scheme was commissioned in 1975, but has been out of operation during the years of insurgency in Mozambique.

23. There are plans to develop further hydro sites on the Zambezi, principally at Batoka Gorge, below Victoria Falls, but also at Mepanda Uncua, downstream of Cahora Bassa. This latter site is a storage dam and also linked to possible developments on the north bank at Cahora Bassa. The Batoka scheme is run-of-river and based on studies which show that conjunctive operation (between power plants) can more than double the energy potential of the river system for any given flow regime.

24. Zambia has hydro plants at Kafue Gorge (900 MW), Kariba North (600 MW) and Victoria Falls (108 MW). These plants represent 90% of the installed capacity on the Zambia 330 kV interconnected system, which extends to the Copperbelt in the north of Zambia, and is connected to the Zimbabwe 330 kV network at Kariba. Zambia normally exports power to Zimbabwe via this interconnection, which in 1986 stood at 3000 GWh, making this the largest electricity trade arrangement in Africa.

25. The hydro resources in Zimbabwe are exclusively at Kariba South, and total 750 MW with upgrades complete. The main thermal generation is 920 MW at the minemouth coalfired plant at Hwange and 325 MW of 'old thermal' coalfired plant in the main cities. All generation is integrated via a 330 kV transmission network and this network, interconnected with Zambia, is close to 5000 km in length.

26. Botswana has 207 MW of generation, based on Moropule and exclusively coal-fired thermal. Botswana's first link was with RSA in 1980, when a 132 kV transmission line was built to provide power to Gaborone from Spitskop. This link is now being upgraded by the addition of two further 132 kV lines. In the early 1980s there was no connection between the north and south of the country. These regions were only interconnected in 1985 by 220 kV transmission, with the commissioning at the same time of Moropule. Later, in 1990, a 220 kV line was built connecting the Botswana and Zimbabwe power systems. This line is from Bulawayo in Zimbabwe to Francistown in Botswana, but there are technical problems necessitating operation as an open tie when the network is interconnected with RSA.

27. Electricity supply in South Africa (RSA) originated in 1890 in Kimberley followed by Johannesburg in 1891 and then other major cities. The Electricity Supply Commission was established in 1923. ESKOM, as the RSA utility is known today, began generating electric power in 1925 and today has an installed capacity of approximately 36,000 MW, almost all of which is coal-fired thermal plant. Some 8000 MW of this installed capacity is considered surplus, and can be made available to offset energy deficits due to drought through interconnection.

28. The idea of an interconnected transmission system linking all the major cities in RSA originated in the 1920s, when the need to supply power to the entire country was identified. This became a reality fifty years later in 1973, when all the ESKOM sub-regions were strongly interconnected via 400 kV and 275 kV transmission lines. ESKOM now has more than 220,000 km of power lines of which 22,000 km are part of the national grid. In 1987, the first 765 kV lines were energised. ESKOM thus developed from very small undertakings to a large, strongly interconnected, national utility.

29. Total electricity sales by ESKOM in 1992 was circa 138,000 GWh, whereas the 1992 energy demands of BPC, ZESCO and ZESA were 1122 GWh, 6890 GWh and 10751 GWh, to give an aggregate demand of 18,763 GWh. This aggregate as an "interconnected" total is about 91% of the core-country SADC demand, viz: also including Malawi and Mozambique, and is only 14% of the RSA energy demand. The capacity and energy forecasts for the region suggest an average annual growth rate of 3.6%, and thus demand is expected to double in 20 years.

30. Assuming reasonable supply/demand balances within the established SADC Grid, the market for trading hydro surpluses in the region will be RSA, where 98% of the present demand is met by thermal generation. It follows that regardless of their thermal surpluses now or in the future hydro imports are attractive to gain reductions in operating costs. For this reason, ESKOM are planning to return Cahora Bassa to service without undue delay, and foregoing the use of one generator (M) to ZESA is a significant concession in the interests of regional co-operation and power pool development.

31. In comparing 1990 resources and demands for BPC, ZESA and ZESCO from the AAA3.8 Report, as shown in Table 1.1, there is an aggregate of 3642 MW generating capacity for the three SADC utilities compared to a combined undiversified peak load of 2564 MW. With the peak demand projected to almost double in the combined network by 2010, there is a need for at least 1000 MW of new generation capacity and power sharing to meet demand together with imports from Zaire and RSA. Good trading relations and strong interconnections are therefore an imperative for a healthy power supply.

Table 1.1

	Peak Load (MW)			1990 Generating Capacity (MW)
	1990	2000	2010	
1. BPC	160	255	415	197
2. ZESCO	866	1031	1396	1622
3. ZESA	1538	2201	2902	1823
4. Total	2564	3487	4713	3642

Operational issues and problems

32. Since 1973 ESKOM has developed radial interconnections with other power utilities in the region, including BPC (Botswana), SWAWEK (Namibia) and EDM (Mozambique), Table 1.3, from a UNIPEDE paper¹, summarises most of the important regional interconnections. The radial links present few problems in the control of power flow. The possibility of parallel operation between ESKOM, BPC, ZESA and ZESCO is a very different matter, as the networks are disparate in size and some links are weak.

33. The BPC link to the ZESA/ZESCO networks is a particular problem. The link is impossible to control manually and is therefore operated as an open tie. There is a similar problem with the interconnection between ZESCO and SNEL. However, in that case it is easier to control manually because the DC line provides an asynchronous link. In all power systems, including those with DC links, it is evident that, short of a system collapse, load is always followed by the frequency response mechanism. Hence, suitable automatic generation control (AGC) must be applied if the SADC networks are to be fully integrated with the ESKOM network and operated as a power pool with the transfer of firm power. AGC is the mechanism whereby generator power output is adjusted through "governor droop" in response to a change in system frequency.

34. The main problem with the BPC system is that it is much weaker than the ESKOM system on one side and the ZESA/ZESCO system on the other side. It follows that any load-generation changes in the northern system would result in unfavourable power swings and

¹ La Grange, J.H, et al: The Development of a Southern African Interconnection - an Operational Perspective; UNIPEDE Conference, Tunis, May 1993.

system collapse. The problem can be overcome by the installation of tie line and frequency bias automatic generation control (AGC) at Kariba. Furthermore, AGC is an imperative for firm power transfers, and a condition for the proposed 400 kV Matimba-Bulawayo interconnection between ESKOM and ZESA. Implementing AGC facilities is therefore one of the urgent activities of the newly constituted IOPC.

35. ESKOM is the only utility to have AGC in operation, although BPC has an AGC system not yet in commission. An AGC system on some of the units at Kariba is being implemented, but is not yet available. The proposed control strategy is that each participating utility of an interconnected system should act as Control Area Operators. This is the standard control method for large interconnections, and does not assign frequency control to any one area. In this respect the importance of and degree of load following is not an individual choice. Uniformity of control must be maintained throughout the interconnected systems in order to avoid chaotic unbalances and ultimate system collapse.

36. Regardless of the type of pool, all participating utilities must be responsible for their own area balances, and regulate their inter-area ties in a manner that permits a predetermined departure, known as the "area control error" (ACE) from a scheduled flow for a given variation in system frequency. ACE is basically a function of system stiffness and tie line bias control. System stiffness (K) is the load/frequency (MW/Hz) characteristic of a network, and is a measure of the system response following an instantaneous change in load or generation. For large systems such as the ESKOM network the value of K is at least 2500 MW/Hz, but for small systems like the BPC network K is about 200 MW/Hz. ESKOM is thus an order higher than BPC in stiffness, and also with any of the SADC networks.

37. AGC trials were carried out in May/June 1992, in which ESKOM and BPC were synchronised with ZESA, ZESCO and SNEL. The tests showed that power on the ESKOM/BPC tie built up to a scheduled value of 65 MW, and once up to this value it was found that the ACE signal tended to follow the power on the tie. In this test AGC control was far from optimal, as the deviations of power that can be tolerated on the tie were very small compared with the size of generating pool controlling it.

38. As a result of these trials it was concluded that ESKOM should control frequency only, with BPC controlling the frequency and tie line between themselves and ESKOM. Similarly, ZESA would control the frequency and tie line between themselves and BPC, and so on through the interconnected system. This control is not quite the classical method, although it evidently follows UCPTTE practice. However, since all the utilities are connected in series, it generally conforms to the ACE philosophy that the utility which causes the change of power from the scheduled exchange corrects the change.

39. With the introduction of the Matimba-Bulawayo 400 kV line and the new 132 kV lines from ESKOM at Spitskop to BPC at Gaborone, load variations will be less likely to overload tie lines. AGC may hence not be technically essential, but it will continue to be necessary for tariff management of firm power exchanges. This will be effected through the "inadvertent payback" feature of AGC, which ensures that energy shipped over AGC-controlled ties can be returned to scheduled values within a given time period, usually about 10 minutes. The energy is thus "Inadvertent Energy" which should be balanced by the return of an equal amount of energy during the same load (on- or off-peak) period. For tariff purposes, energy NOT so returned is subject to charges which are usually higher than the highest intercept cost in the combined systems, and established annually.

Basis for trade

40. Firm energy sales (energy brokering) between utilities is often the motivating force promoting interconnection and the sizing of plants larger than for local needs. Other main benefits from interconnection such as economies of scale and reserve capacity sharing may follow if a power pool is formed and development is integrated. Among the further "secondary" benefits with a hydro/thermal pool is the scope for placing temporary hydro surpluses in thermal systems as "economy energy". But the fundamental economics of interconnection are usually predicated on firm energy exchanges on a bilateral basis or to a power pool at a competitive price. The key issue is to have a sufficiently large surplus power to make transmission to more distant markets worthwhile.

41. ZESCO has enjoyed large power surpluses, which have invariably been exported to ZESA. Table 1.4 shows the power transfers from 1978 to 1992 over the Zambia-Zimbabwe Interconnector. These average about 460 MW and 2328 GWh annually over the 15 years of record. Income from this trade in the mid-80's ranked second, after copper, in US\$ foreign exchange earnings for Zambia. There is general satisfaction by Zambia and Zimbabwe with the export tariffs and arrangements, and the link is inherently firm with no recorded faults except for relay maloperations.

42. The basis for the pricing of exports from Zambia is that the exports and internal revenues associated with the assets must together meet the minimum of 8% on assets at replacement value. In the case of exports to Zimbabwe from Zambia the assets comprise Kariba North Power Station and associated facilities. A later development, a spin-off from the ZESCO/ZESA/BPC Agreement, is the introduction of economy energy. This is worked out as 70% of the short-run marginal cost (SRMC) of thermal plant. The three utilities (ZESCO, ZESA, BPC) have reached agreements on the conditions for eligibility to import economy energy as follows: the purchasing utility must satisfy the provisions that (1) all its plants are available, and (2) must demonstrate self-sufficiency in generation. The latest agreements also recognise an arrangement between SNEL and ZESA whereby ZESA imports up to 120 MW from SNEL, wheeled through the ZESCO network.

43. Various agreements have been made over the years, but the latest are as follows, and between:

- **SNEL & ZESCO**, dated December 1992 for the firm power import from SNEL of 100 MW at 100% load factor.
- **ZESCO & ZESA**, dated September 1993, and covering a new export/import arrangement for firm supply and reserve capacities.
- **BPC, ZESCO & ZESA**, dated September 1991, for the import by BPC from ZESCO of firm power and surplus energy wheeled through the ZESA network.
- **ZESA & ESKOM**, dated May 1993, and principally concerned with power to be delivered to ZESA by ESKOM over the future 400 kV Matimba-Bulawayo line.

44. All these agreements follow a set format, but they are in no way generic as each agreement has its own special features. All the bilateral agreements consist of a negotiated supply from one party to another and are utilised in the context of a firm power transaction that replaces the provision of firm power generation in the purchaser's power system. Tariffs are negotiated for payment in convertible currencies on the basis of avoided cost formulae plus escalation, and are expected to have a term of up to 10 years. It has been suggested that such agreements must remain available to parties even under a regional pool arrangement.

45. In the present agreements there are also provisions for the sale of energy surpluses either as supplementary or economy energy. In the latter case the buyer purchases assured economy capacity, and restricts the generation of energy from his own capacity, or otherwise restricts the purchase of energy available under other contracts.

46. Table 1.2 provides details of the tariff arrangements (and prices) that apply for bulk supply exchanges within the region. This table (compiled by Dale, 1993) also provides a brief

description of the interconnectors, including capability. One of the more important comments from an associated paper² emphasises that all utility agreements are supplemented by agreements between governments, to give legal standing to the former. This clearly demonstrates the role of government in the power sector.

47. The Agreement between ZESA and ESKOM is unique, as it has been negotiated before the 400 kV Matimba-Bulawayo line is built. Also the range of services is much wider than might normally be expected in a Supply Agreement. To investigate the type of service that ESKOM could provide to ZESA, the two systems were simulated together, taking into account drought-related stochastic variables and other operational factors together with the utility' development plans. The results showed that the line (now known as Matimba-Insukamini) will not carry large amounts of energy if the ZESA demand is balanced with largely hydro resources, as is expected.

48. Energy from ESKOM, being wholly thermal, is generally more expensive than energy in the ZESA system, and thus should be imported (by ZESA) only as a last resort. On this premise the line is expected to operate with an average load factor of 10-25 percent, with ESKOM allowing ZESA access to surplus thermal capacity, basically as insurance against deficits due to drought. At the signature of the Supply Agreement, ZESA committed themselves to 400 MW of capacity in 1995, 300 MW in 1996 and to 150 MW afterwards until 2003. This is a fairly common transaction between a utility, such as ESKOM, with excess capacity and energy and one that suffers capacity and energy shortages, as does ZESA.

49. Both Parties accept that the Agreement is mutually beneficial, and for this reason the interconnection is justified. ESKOM will recover capital and other fixed charges on assets incurred in plant that it currently does not need, and ZESA will be able to:

- alleviate the need for load rationing in its control area in times of drought;
- postpone investments in new plant (Old Thermal rehabilitation, Hwange 7&8); and
- purchase energy from ESKOM only when it is economical to do so.

² Dale, A.P: Some Key Features of Power Exchange Agreements for Southern Africa; SADC Seminar on Inter-Utility Exchange and Pricing Policies, Sept. 1993.

50. The risk of ESKOM not having the contracted capacity is very low in view of the large excess capacity (currently about 8000 MW) and the limited period of the contract. The starting point for pricing this excess capacity is the levelised capital plus fixed base-load production costs.

Power supply reform

51. As noted by Gata (1990)³ - "The electric power utility in most developing countries is almost entirely driven and managed through the political system in contrast to the practice in the largely market-led economies of the developed nations". The electrical power industry in the region is invariably government owned, highly centralised and politically regulated. Although the region has no shortage of resources for economic power generation and supply, the utilities outside the RSA have performed poorly through the 1980s. It is now accepted that this is because of institutional weaknesses, which could be removed by private sector participation.

52. Power utilities are invariably vertically integrated and responsible for all aspects of production, transmission, distribution and marketing. Furthermore, utilities are often used by government as an instrument of social and economic policy. Utility managements are appointed by Government and the decision making process is based on delegated authority, often variable and rarely specified. This is perhaps an inheritance of a past colonial era, but there is now a wind of change, as governments look to private investment as a means to reduce the burden of financing power sector development. There is now the clear notion that market-orientated competition will result in greater economic efficiencies.

53. Private-sector participation for project financing in the region is beginning to be encouraged, mostly because investment requirements are outstripping the funding resources of international aid agencies. But it may take time for the appropriate legislation to be implemented. In the meantime, the most favoured approach is financing via suppliers' credit arrangements under which goods and services, or a combination in the form of turnkey projects, such as BOOT-type schemes, are procured on favourable and often aid-supported terms.

³

Gata, Z.S: Impact of Policy and Institutional Infra-structure on the Management of Energy Enterprises in Developing Countries; ESA Energy Forum, Nov.1990.

54. The administrative unbundling of generation, transmission and distribution, and mandatory third party access to the networks is not considered a high priority. The view was generally expressed that (utility) independence from government was more important than privatisation. It was also suggested that decision-making would improve with more business executives on utility boards, rather than Government Civil Servants.

55. There are government initiatives to encourage private generators in Zambia and Zimbabwe, the latter with respect to mine-mouth, coal-fired, generation. In this respect, drought-related power deficits cost Zimbabwe 12% on GNP, and industry is lobbying for thermal generation.

56. No opinion was expressed with respect to "Third Party Access" (TPA), although it is accepted that this must be considered if private non-utility generators (NUGs) are accepted and given freedom to trade with bulk consumers.

Costs and benefits of interconnection

57. This section attempts to focus on identifying the costs and benefits of interconnection; and, where possible, quantifying according to the options for interconnection use for both existing and new interconnections.

58. Much of the generation and transmission infrastructure in the region was built in the colonial era and has been in service for up to 30 years. This plant is now a sunk cost and so benefits and costs can mostly only be measured in terms of "change of use". In this respect, investments in transmission facilities cannot easily be recovered if the specific facilities cease to be used, and the resources invested cannot be easily shifted to other employment.

Concept of avoided (marginal) cost

59. Avoided cost is defined as the cost a "buying" utility would otherwise incur if it were not for power purchases from a "seller". The theoretical basis for avoided cost derives from marginal cost determination of short/run and long/run changes in the use of electricity.

60. In a utility environment it is difficult if not impossible to explicitly measure benefits or penalties resulting from a change of use of electricity, thus an alternative is to measure the impact on the avoided or marginal cost of supply. The costs of new facilities are considered as marginal costs for supplying changes in electricity use. The technique is well appreciated in the region, and was discussed as a means to converge on least cost development, and, more importantly, establish the cost of a given level of self-sufficiency

61. The marginal cost in the shortrun is basically the cost of using existing facilities more or less often. If existing facilities are not adequate, then changes in reliability take place. This can give the justification for a transmission interconnection; for example the 400 kV Matimba-Bulawayo line. A similar scenario could apply in mitigating losses and improving economic despatch strategies to minimise production costs without impairing reliability, e.g. by purchasing economy energy.

62. In the longrun it is necessary to evaluate permanent efficiency improvements that derive from the use of interconnections. The way to calculate benefits or avoided costs for a change that is expected to last for several years is to calculate the cumulative net present value of the annual avoided costs in terms of capital investment and operations to a total systems base, as was the case in the recent SADC Energy Project AAA3.8.

Regional versus independent development

63. As noted in a WEC paper⁴, "a selfevident caveat for successful interconnection is that the benefits and costs must be distributed so that all participants gain over the alternative of independent power development". This caveat has a major influence on the way developing countries choose to meet their need for electricity, as investments in the power sector are very capital intensive. Sharing the investment burden is considered the main advantage of electrical interconnection, as it makes possible the aggregation of power supply markets and infrastructure between participating countries.

64. This thesis was applied to investment studies in the recent SADC Energy Project AAA3.8. The intent was to equitably distribute the benefits of interconnection and integrated development of generation and transmission capacities, to a single power system or "tight" pool arrangement. The countries involved were those with close access to the Zambia-Zimbabwe 330 kV transmission system and therefore able to participate directly in the co-ordinated development via interconnection. These countries are Botswana, Malawi, Mozambique, Zambia and Zimbabwe, as shown in Fig.1.1.

65. It was demonstrated⁵ that savings of up to 20% could be achieved by regional co-operation and interconnection, instead of each country following an independent, or self-sufficient, power development track. Savings were basically realised by making more effective use of existing generation resources, by a strategy of extending and reinforcing the existing interconnected transmission system; including links to Zaire and RSA as appropriate. The resulting benefits were achieved through

⁴ Lewis, W.P: Opportunities in Africa for Energy Cooperation - The Case for Transmission Interconnection; Paper 4.1.04, WEC 15th Congress, Madrid, Sept.1992.

⁵ ESMAP: SADC Energy Project AAA3.8 - Regional Generation and Transmission Capacities, including Interregional Pricing Policies; Phase II Technical Report, prepared for ESMAP by EPD Consultants (UK) and issued April 1992.

economies of scale, the sharing of reserves and the postponement of new investments; they were applied to an integrated plan, as shown by the summary of development costs in Table 1.5. The drought scenario is the plan that is being followed, with the rapid installation of the Matimba-Bulawayo line.

66. The exercise was undertaken using formal planning methods in which alternative plans are made technically equal in reliably meeting a future demand, and then economically ranked in order of least cost. To facilitate measurement of benefits integrated plans were compared with the aggregated costs of independent power development. Plans A and D in Table 1.5 compare a wholly hydro development with a hydro/thermal generation mix, whereas the drought scenario examined the impact of importing power from ESKOM. The intermediate scenario addressed the effect of reducing Malawi's import dependence. All these integrated plans show savings over independent power development, in which unserved energy ranked as a very significant additional cost together with the greatly increased capital investment burden.

Specific costs and benefits

67. The strategic importance of transmission is much greater than is indicated by its share in the over-all cost of electricity supply. Specific benefits that accrue from network interconnections are:

- lowering of generation capacity reserve requirements;
- ability to achieve scale economies;
- opportunity to interchange economy energy;
- increased load and fuel diversity;
- opportunities for sale of surplus firm energy;
- emergency support on major breakdowns.

68. These benefits can be regarded as system wide insofar as they are germane to the objectives that load demand be reliably served at minimum total system cost. Total system cost is the relevant measure because it allows for the output interdependence of generating units in an integrated power system to be explicitly introduced in determining the economics of electricity supply, as represented by marginal costs. For example, economies of scale have been achieved without degrading reliability because of the Zambia-Zimbabwe systems being integrated. As pointed out in Reference 4, this has saved at least a 900 MW power plant. Breakdown support between ZESCO and ZESA, with respect to problems at Kafue and Hwange, have resulted in savings in energy not served.

69. All of the above benefits have been realised in the SADC Grid comprising the ZESCO, ZESA and BPC networks, and the intent of new interconnections is to consolidate these benefits at minimum cost. The new interconnections are the Matimba-Bulawayo line and the Songo-Bindura line. The latter provides interconnection of the Zimbabwe (ZESA) network to the hydroplant at Cahora Bassa, and access to 400 MW of "spare" generating capacity. The 220 kV link between ZESCO and SNEL has recently been strengthened at a very nominal cost (< US\$0.5m) and now is capable of a firm transfer capacity of 200 MW. These are all projects that were endorsed by the SADC AAA3.8 Phase II Study as short-term measures to underwrite supply integrity.

70. There are now plans to further increase the capacity of the SNEL-ZESCO link, based on recent combined studies⁶ by ESKOM, SNEL, ZESCO and the Zambia Consolidated Copper Mines (ZCCM). The decision to undertake these studies was made at an Emergency Drought Regional Planning Meeting in July 1992. This meeting was convened to consider means to overcome shortages of electrical energy in Zambia and Zimbabwe if the present drought continued indefinitely. Reduced water inflows have highlighted the benefits of interconnecting southern Africa's hydro resources with RSA's existing thermal generation surplus, about 8000 MW. Furthermore, in spite of the drought, some countries in the region experience power shortages, e.g. Zimbabwe where demand exceeds supply and reliance is placed on imports.

71. Drought is a major concern, as it is very clear that the Zambesi River is subject to long cycles of wet and dry years because the catchment is entirely south of the equator. Furthermore, hydrological analysis shows that the region is now in a dry cycle that may last for another ten years. In the case of the Congo (Zaire) River the tributaries span the equator and thus are not subject to the same climatic cycles as the Zambesi. As a result the energy output (at least from Inga) is more certain. Strong interconnection with SNEL is thus an imperative for reliable hydro energy in the region.

72. Clearly, instead of further generation development, increased regional trade, based on existing generation surpluses, will permit more efficient utilisation of resources and increase reliability of supply in the short and medium term. The emphasise for the next decade should be on interconnection in preference to further generation expansion, so that existing large blocks of power are moved to areas that are experiencing shortages.

73. With an additional US\$500 million, half of which is already secured, the new interconnections can be implemented together with other upgrades including the Zambia-Tanzania link (or "5th Corridor") proposed in the AAA3.8 Phase II Report. With these links in place the savings from electricity exchanges are likely to quickly reach at least US\$125 million per annum. This represents a very positive return on investment with a 4-year payback. Furthermore, if RSA were prepared to accept,

⁶ ESKOM/SNEL/ZCCM/ZESCO: Zaire-Zambia 220 kV Transmission Development - Kolwesi-Luano Power Transfer Capability Improvement Investigation, May 1993.

for instance, 15% of its total maximum demand from external hydro sources, say from Zaire through the SADC network, this would create a firm power market for at least 3000 MW based on the latest (1993) demand statistics.

74. The wheeling analysis of SADC AAA3.8 showed that some 1500 MW could be wheeled through the SADC Grid from Zaire to RSA with only minor reinforcement to the main network and the addition of a 400 kV link between Serenje (Pensulo) in Zambia and Songo in Mozambique via Lilongwe in Malawi. Some of these costs are already in the US\$500 million budget. Thus, if an "export" scenario to RSA is developed and operated as base load, it would result in sales of 20,000 GWh per annum and a revenue of US\$600 million, based on a firm power import of 3000 MW. This revenue represents some 10% of the GNP of Zimbabwe. As an aside, this indicates the cost of the drought-led power deficit in Zimbabwe (with a drop of 12% in GNP).

75. The above US\$600 million revenue has been estimated at US\$30/ MWh, the present short-run marginal cost (SRMC) of electricity supply in RSA. This SRMC gives a measure of the avoided cost of electricity supply in RSA on the basis that new plant is not required to meet demand. As present surpluses are eroded by demand growth the avoided cost can be expected to increase towards the long-run marginal cost (LRMC), which is thought to be US\$80/ MWh.

76. Concluding this section, it is clear that lower risks are associated with interconnection. High fixed costs can be avoided and it is often cheaper to import energy. In an operating environment where skilled human resources are scarce, operating constraints are reduced. Utilities are thus able to improve the performance of existing power plant, rather than allocate these resources to the construction of new power stations.

Issues and constraints in energy trade

77. There are economic forces drawing the region together, and political activities which serve to divide. This much is evident from mere observation, and it is not a new phenomenon. Nor is it likely to reduce in the future, and proposals for any extension to present regional inter-action must take account of this dichotomy between economics and politics. The optimism for interconnection must be qualified by noting that much of this is due to the politics of necessity, latterly from the drought: witness the loss to Zimbabwe's economy of a 12% reduction in GDP estimated at close to US\$1 billion. This is the amount currently estimated to build Batoka - expected to be the next big hydroplant on the Zambesi.

78. To date, despite the formation of institutions such as SADC, relations between the countries of southern Africa are characterised by varying degrees of suspicion and even hostility. It must be recognised that economic linkages are no guarantee of stability and, they can be the cause of conflict: witness the decades of strained relations between Zambia and Zimbabwe; now about to argue at the International Court about the ownership of Kariba.

79. In this section the intention is to focus on those issues which may constrain increased trade and the forming of a power pool. The issues are categorised as institutional, commercial, economic, financial and technical, and are discussed in two groups: constraints to increased trade and obstacles to realisation of potential benefits.

Institutional issues

80. The most basic constraint to increased trade must be a lack of mutual trust and openness. However, following the Malawi Conference this may change, and there is hope that the IOPC will be a forum for information exchange. More importantly, there are widely divergent conceptions of "dependence" and "interdependence". The "dependence" issue is still generally perceived as a major obstacle to gaining the full benefits of interconnection, because of a reluctance to give up some autonomy. This particularly applies to energy import dependency, as the energy deficient country usually has self-sufficiency concerns. There is a debate on the level of self-sufficiency, and studies are being undertaken to determine the level of essential demand. However, one senses an absence of any real commitment to "interdependence". Consequently, the political capacity to implement and sustain significant sector responsibilities, whether planning or operations, may not yet be present.

Financial/economic issues

81. Most States in the region suffer from budget deficits, rampant inflation and local currencies are over-valued. This has resulted in shortages of convertible currencies, despite recent efforts to liberalise foreign exchange allowances. On the matter of economic policy there can be no guarantee that past mistakes will not be repeated or perpetuated. Poor economic performance must thus remain a potential, if not actual, impediment to any increase in energy trade and the development of a power pool.

82. All interconnection agreements require payments to be made either in US\$ or Rand, the latter being the only hard currency in the region. Tariff escalation is also calculated according to movements in hard currency. The US Consumer Price Index is used, or, alternatively, ESKOM's own annual escalation rate. There is thus a degree of financial dependency as revenues for a power exporter must be in a strong and scarce third currency. In the case of Zambia, revenues from power export make a significant contribution to the national economy. It follows that if financial dependency is perceived as a problem, alternative power markets may be sought, and less reliance placed on existing power exchanges. This may prejudice the further development of a regional pool.

Contractual issues

83. Negotiating processes within the region have varied from apparent benign acceptance of the supplier's domestic tariffs to extended and lengthy wrangles between the parties concerned. The latter problems have mostly involved negotiations on wheeling concepts and charges. These have generally been very difficult, with desires for short term gains outweighing longer term benefits. The utilities concerned appear to find it difficult to put into practice their earlier approval (at SADC meetings) of the principle of equitable sharing of benefits. This must be a constraint to increased trade.

84. Crucial among lessons learned from the interconnection of the ZESA and BPC Grids, was the need to have in place tariff agreements before the project was implemented. This point by K. Sithole (CE of BPC) made in a paper⁷ at the 1993 Malawi Conference on "Interutility Power Exchange and Pricing Policies" was reinforced as follows: "Donors should insist on this being a pre-condition for financing any viable project. Any other approach could lead to a situation whereby projects are implemented through to completion and become temporary white elephants while pricing negotiations go on endlessly".

85. There was great bitterness over these negotiations, and a lack of trust was clearly evident. It is noteworthy that the same mistake has not been made with the Matimba-Bulawayo Project. All the agreements have been signed, and the Project can now proceed. BPC will eventually benefit from this Project, as the line is routed via Selebi Phikwe and provision is made in the agreement for a step-down transformer substation. This will enable BPC to obtain a direct supply at 400 kV from ESKOM in the future, in return for allowing the line to be routed through Botswana. This dispensation has reduced the line distance and costs by about 20%.

86. A de facto "loose pool" arrangement has already emerged as a result of the Matimba-Bulawayo Agreement, and the expansion of IOPC membership to include ESKOM. However, this agreement is a direct consequence of the drought and other ZESA difficulties, and may not survive the emergency. In this event, the most obvious reason will be the highly asymmetrical relationship with RSA, as well as between Zimbabwe and neighbouring SADC countries. This is considered a very important potential impediment to the realisation of the future benefits of interconnection as power flow is reversed and imported to RSA. It would most probably result in no further development at 400 kV.

7

Sithole, K: Interconnection of the Zimbabwe and Botswana Grids; SADC Energy Seminar - Interutility Power Exchange and Pricing Policies, Malawi, August 1993.

Legal/regulatory issues

87. There are usually five legal documents covering the rights and obligations of the parties arising from an interconnection. These are:

- Government to Government Memorandum of Understanding, granting permission for the utilities to make a contract and providing guarantees with regard to obligations resulting from an interconnection contract;
- Inter-Utility Agreement between participants, defining ownership of assets and other rights, e.g. the erection of future substations;
- Supply Agreement for power/energy exchange, and governing the commercial arrangements;
- System Operating Agreement, determining the interaction between the utilities with respect to operating responsibilities under normal and emergency conditions; and
- Maintenance Agreement, defining the sharing of costs and functional responsibilities for plant maintenance including safety rules and notices.

88. The agreements are quite complex and take a great length of time to negotiate. They include binding arbitration clauses, clauses relating to "force majeure" and the "law" of the agreement. The Government-to-Government Memorandum of Understanding must include undertakings for the release of convertible currency for the payment of power imports as a cardinal obligation.

89. The delays and uncertainties that seem implicit in the process are a cause for concern, as the window for economic viability in some proposals is often very narrow, e.g. the Songo-Bindura interconnection. When exacerbated by other factors such as negotiating funding, and the adjudication and award of construction contracts, the delays can become intolerable, and prejudice the realisation of benefits from the interconnection.

Technical issues

90. Capacity transfers to achieve regional balances in the SADC network are unlikely to exceed 1000 MW, and this is roughly the capability of the present AC transmission system. Only in the event of very large "wheeling through" power transfers would it be economically feasible to consider new DC developments; AC reinforcement as presently envisaged will only marginally increase power transfer capacities. Furthermore, AC interconnection beyond the present plans may not be cost effective, given the length of the regional network at close to 5000 km. More radical concepts are needed to avoid network capacity constraints.

91. One such concept may be the use of Flexible AC Transmission System (FACTS) Technology as proposed by Hungarian⁸. This is the name given to concepts of transmission line control using thyristor devices, such as the static VAR compensator (SVC). The SVC was introduced years ago, acting as a shunt capacitor or reactor, to produce or absorb reactive power (VARs). In this way voltage stability can be maintained. The latest development is the "controlled series compensator" (CSC), which can effectively damp power swings by reducing the series impedance of a transmission line. The FACTS devices are thus already available, and are now being considered in the detailed design of interconnections. A fundamental notion behind FACTS is that it is possible to continuously vary the apparent impedance of specific transmission lines so as to force power to flow along "contract paths". The contract path idea is an entirely new concept in system control, and using FACTS devices it should soon be possible to maintain constant power flow along a desired path in the presence of continuous changes of load/generation in the "external" AC network. This offers great potential for firm power wheeling. It has now been demonstrated that by using FACTS devices high speed control of transmission is possible. It is thus expected that secure loadings of transmission lines can be significantly increased to their full thermal rating. This will remove the conservative power-distance constraints presently applied to long distance AC transmission. It may now be practicable to improve the dynamic performance of existing AC networks without adding more lines. In the case of the SADC network these devices could double the present capacity. Development in the UK is focused on making the devices "relocatable". In this way as loads and generation change over time the FACTS equipment are moved to new "strain" points in a network. In the SADC milieu this will add a new dimension to co-operation and power pool operation.

92. Present problems in the technical operation of the power system are concerned with load/frequency control for firm power transfers, as already discussed. In fact, several contractual provisions cannot be consummated without this control using AGC and applying ACE concepts.

⁸ Hungarian, N.G: FACTS - Flexible AC Transmission System; International AC and DC Transmission Conference, IEE Savoy Place, London, 1991.

This is the most immediate action, the implementation of which will test the ability of the utilities to co-ordinate their operations and apply due diligence and discipline.

Key lessons from case study

93. In concluding this report the lessons learned from the Case Study are discussed. In particular, those concerning key issues (constraints) that are bound to the success or failure of interconnection and trading opportunities. In this respect it should be appreciated that the region has a long experience of interconnections.

94. It is encouraging that SADC utilities are undertaking or commissioning studies to establish development plans, and that recent interconnection proposals have all resulted from joint studies by the main participants. The view has been expressed that the IOPC should become more involved in planning studies, and in particular with the forecasting of "avoided costs", to determine how costs and benefits should be shared in a pool system. After the 1993 Malawi Conference, there is the hope that a greater spirit of trust and openness will prevail, as lack of such a spirit is recognised as the greatest impediment to increased trade and progress towards a regional pool.

95. These sentiments are indeed enshrined as fundamental principles in the preface to the IOPC Draft Terms of Reference (TOR). It is also made a principle that member utilities shall have equal rights and obligations, act in solidarity and not take advantage of each other. By accepting this document, members also agree inter alia to share information and knowledge; be politically neutral; develop common planning/operating procedures; and bind themselves to accept wheeling and the conditions of wheeling. Acceptance of this TOR thus sets the scene for the development of a Southern Africa Power Pool (SAPP), already discussed as the priority for the next decade, to enable the movement of large blocks of power to areas experiencing shortages.

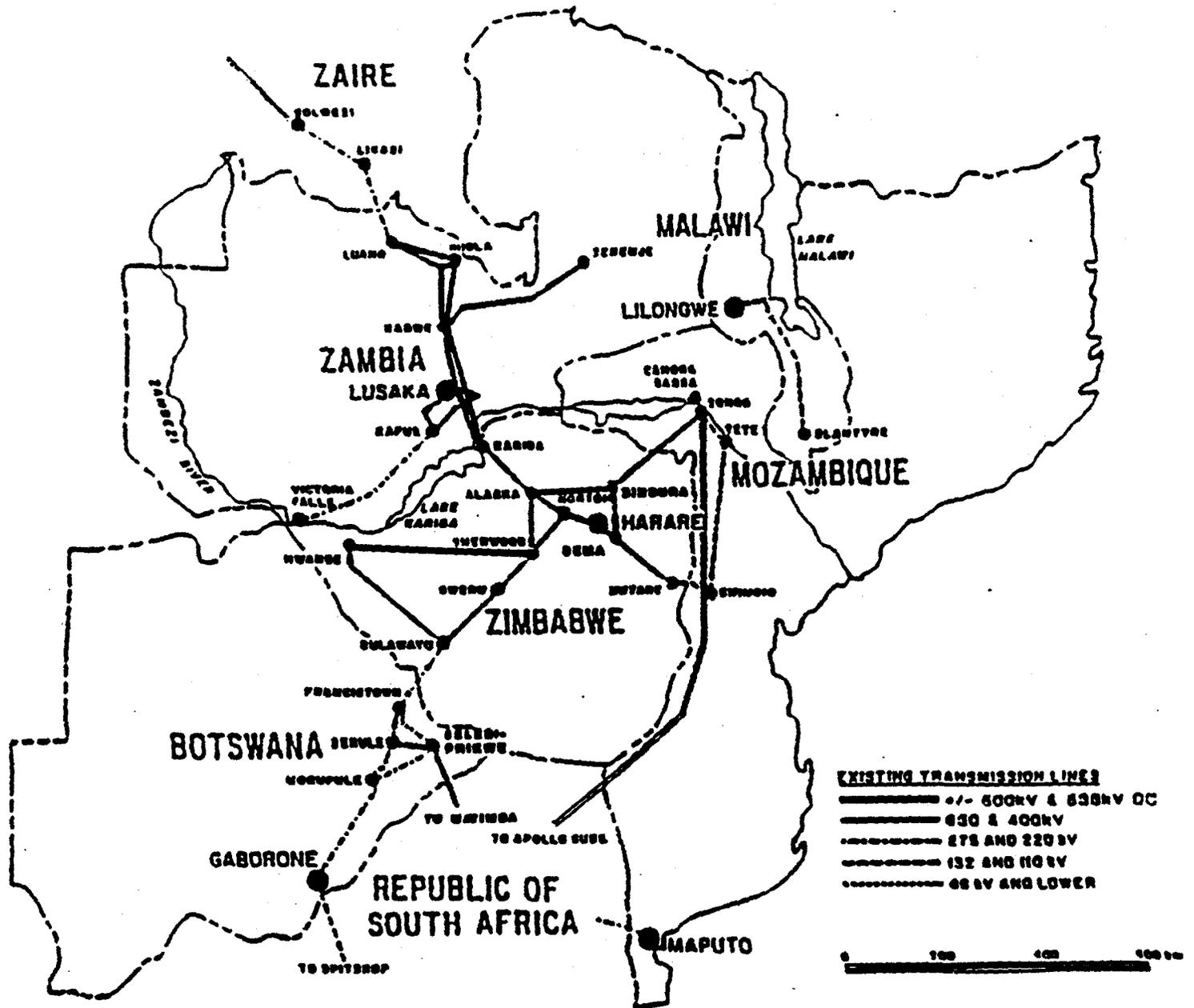
96. If SAPP is not to be still-born, national governments must relax their present rigid controls over every facet of utility operations. Concurrently, actions must be taken to relieve the utilities of their chronic debt burdens. These debts mostly result from the utilities adopting the role of an agent of government policy, with emphasis on production, and the undue reliance on external financing and technical support.

97. It is noteworthy that as a result of national governments' quest for prestige projects and to increase self-sufficiency, southern Africa now has enough generating plant **already installed** to cater for the electricity needs of the region until at least 2005. Clearly, the emphasis for the next decade must be on interconnection, to more effectively utilise existing generating resources in satisfying demand at an acceptable level of reliability and at least-cost.

98. One of the main impediments to further interconnection is evidently the physical capability of the electrical network. Decisions will have to be made soon on how the overall network should be upgraded. Perhaps this could be the first main task of the IOPC, once it has secured the integrated operation of the power system with AGC control of generators and area despatch according to ACE rules.

99. An option for development is HVDC, since for very long distances coupled with large transfers the HVDC option has clear technical and economic advantages over AC transmission. This will be particularly relevant if interconnection is extended to Mbeya in Tanzania (the fifth corridor of the AAA3.8 Study). The concept in this instance is to provide access to potentially substantial exports of power from Tanzania, circa 2000MW+, that could be realised by the development of the Songo-Songo gas field and hydro resources such as Stiegler's Gorge. In this respect, a multi-terminal HVDC line, from Selebi Phikwe in Botswana via Livingstone, Kafue and Serenje in Zambia and on to Mbeya in Tanzania, would provide a much needed regional "backbone" to secure network capability without constraint to the integrity of individual utility networks and developments.

Figure 1.1



*Source: Phase II Technical Report, April 1993
SADC Energy Project AAA3.8*

Table 1.2

FEATURES OF (BULK) POWER SUPPLY AGREEMENTS IN SOUTHERN AFRICA - AUGUST 1993.

Ref	UTILITIES INVOLVED	INTERCONNECTOR/S					PRESENT TARIFF ARRANGEMENTS (Prices in mid 1993 US\$)										NOTES
		# lines & kv	Gen. Source	Max MW	Terminal Substations	Year in service	Type of exchange	Firm Power	Non-firm Power	Firm Energy	Non-firm Energy	Wheel. Charge	Term. Date	Inflation	Currency	Est. avg US\$/kWh	
1	ZESCO to ZESA	2 x 330kv	Hydro	500	Kariba N./Kariba S	1961	100MW firm surplus	10.42/kW/m 0.342/kW/d	if avail	n/c n/c	-	-	Jun95 Jun95	US CPI US CPI	US\$ US\$	1.50 1.50	assuming 95% LF daily on request
2	SNEL to ZESCO	1 x 220kv	Hydro	200	Karavia/Luano	c.1955	standby 100MW opt'n	- 10.42/kW/m	-	- n/c	-	-	Indef Jun95	n/a US CPI	kWh US\$	n/a 1.50	refund in kWh assuming 95% LF
3	SNEL to ZESA via ZESCO	220/330kv	Hydro	200	ref: 1 & 2	1961	100MW firm 100MW opt'n	10.42/kW/m 9.549/kW/m (May-Sep) 8.681/kW/m (Oct-Apr)	-	n/c n/c n/c	-	17.5% 17.5% 17.5%	Jun95 Jun95 Jun95	US CPI US CPI US CPI	US\$ US\$ US\$	1.77 1.62 1.47	assuming 95% LF ZESCO 1st opt'n on /extra 100 MW.
4	ZESA to BPC	1 x 220kv	Thermal	100	Harvel(Byo)/Fron- clstown	1991	economy	-	-	-	if avail	-	Jun95	act. cost	US\$	0.80	SRMC(M'pule+Mwango)/2
5	ZESCO to BPC via ZESA	330/220kv	Hydro	100	ref: 1 & 4	1991	30MW firm >20MW firm economy	8.833/kW/m 6.183/kW/m -	-	n/c n/c -	-	14.75% 14.75% -	Jun97 Jun97 Jun97	6%/a 6%/a whl 6%/a	US\$ US\$ US\$	1.46 1.02 0.86	assuming 95% LF 30% reduction Oct-May 80% SRMC(Morupule)
6	EDM to ZESA	1 x 110kv	Hydro	5	Chicamba/Mutare	c.1955	emergency	-	-	-	if avail	-	Indef	negot.	US\$	2.50	uprating to 40MW
7	ESKOM to/from BPC	1 x 132kv	Thermal	70	Splitstop/Gaborone	1980	time-of-use daily contr- act	yes	-	yes	-	-	-	ESKOM esc	Rand	1.41	3 lines in 1994. Agree- ment inc. PENALTIES & p'chase surp. BPC gen.
8	ESKOM to SEB	2 x 132kv	Thermal	50	- /Mbabane	c.1970	>50MW firm	6.982/kW/m	-	1.46c/kWh	-	-	-	ESKOM esc	Rand	3.20	Standard ESKOM tariff, assum. 60%LF & 90%PF.
9	ESKOM to EDM	1 x 275kv	Thermal	100	Komatipoort/Moputo	c.1975	70MW take/pay	110MW	-	1.46c/kWh	-	1X tran	-	ESKOM esc	Rand	<3.23	No HD charge >70MW
10	ESKOM to LEC	2 x 132kv	Thermal	50	Maserubrug/Mabote	1992	>50MW firm	6.982/kW/m	-	1.46c/kWh	-	1X tran	-	ESKOM esc	Rand	3.23	88kV since c. 1975
11	ESKOM to ZESA	1 x 132kv	Thermal	40	Messina/Beltbridge	1993	time-of-use	nil	-	peak 2.29c/kWh standard 0.94c/kWh off-peak 0.52c/kWh	-	-	-	SA PPI	US\$	1.65	isolated from main ZESA system. Capital to be repaid in 3 yrs.
12	NCB to ESKOM	DC	Hydro	2000	Songo/Apollo	c.1977	TO BE RENEGOTIATED, but ESKOM can't buy @ 2.0/kWh when ESKOM has surplus gen.					-	-	-	-	0.60	NOT IN SERVICE
13	SWALEK to/from ESKOM	2 x 220kv	Hydro/ thermal	-	-	c.1975	time-of-use energy only	nil	ESKOM buys +/- 250GWh/a and sells 250-600GWh/a.	-	-	-	-	-	Rand	2.34	Sales dependent on Rucana hydrology.
14	NCB to ZESA via EDM	1 x 400kv	Hydro	500	Songo/Bindira	planned 1996	400MW take/pay 100MW extra	5.56/kW/m on request at same prices	-	0.12/kWh	-	see text	Dec03	see text	US\$	1.13	Cost/kWh includes am- ortization EDM invest.
15	ESKOM to ZESA via Botswana	1 x 400kv	Thermal	500	Matimba/Insukamini (Byo)	planned 1995	400MW firm reserve cap. addltn. cap.	7.25/kW/m 0.28/kW/d	-	variable 0.4046c- 0.8295/kWh	-	-	Dec03 see text	US CPI	US\$	var. 1.45 - 1.87	Reduces to 150MW when ref. 14' commissioned. Permits 3rd party wh'l
16	ZESCO to ESKOM	1 x 132kv	Hydro	+/-30	Chipata/Lilongwe	pl.1997	+/-30MW firm	10.42/kW/m	-	n/c	n/c	-	Indef	US CPI	US\$	1.50	assuming 95% LF

Source: A P Dale; Some Key Features of Power Exchange Agreements
for Southern Africa, September 1993

Table 1.3

HISTORY OF THE SOUTHERN AFRICAN INTERCONNECTIONS

Utility (Country)	Installed Capacity	Peak Demand	Tie line between utilities and the year of interconnection.
ESKOM (South Africa)	36347 MW	22640 MW	1.) ESKOM is interconnected to utilities in other countries as indicated below with a #. 2.) ESKOM is also connected to other utilities such as Lesotho, Swaziland, Transkei and Venda.
Others	115 MW	210 MW	
BPC (Botswana)	219 MW	200 MW	1.) #ESKOM via Spitskop-Gaborone 132 kV line in 1980. 2.) ZESA via Bulawayo-Francistown 220 kV line in 1990.
ZESA (Zimbabwe)	1965 MW	1450 MW	1.) * ZESCO and ZESA were connected in the 1960's. At present they are interconnected via two 330 kV lines between Kariba North and Kariba South power stations. 2.) BPC via Francistown-Bulawayo 220 kV line in 1990.
SWAWEK (Namibia)	360 MW	256 MW	1.) #ESKOM via Aggeneys-Kokerboom 220 kV line in 1982.
EDM (Mozambique)	2345 MW	150 MW	1.) #ESKOM via Komatipoort-Sonete 275 kV line in 1973 and a 110 kV line 1991. 2.) #ESKOM via Apollo-Cahorra Bassa 533 kV DC line in 1975.
ZESCO (Zambia)	1608 MW	1000 MW	1.) SNEL via a 200 kV DC line in the 1950's. 2.) ZESCO and ZESA are connected since the 1960's. See ZESA * above.
SNEL (Zaire)	2464 MW	500 MW	1.) ZESCO via a 200 kV DC line in the 1950's. 2.) Congo via Kinshassa-Brazzaville at 6.6 kV in the 1950's, re-inforced by a 30 kV line in 1953 and eventually at 220 kV in 1988. 3.) Burundi in 1979 at 70 kV. 4.) Rwanda in 1979 at 110 kV.

Table 1.4

ZAMBIA – ZIMBABWE INTERCONNECTOR

POWER TRANSFER

YEAR	ENERGY (GWHR)	DEMAND (MW)
1978	1920	295
1979	2523	294
1980	2734	274
1981	3264	517
1982	3508	507
1983	3756	510
1984	3168	497
1985	2809	512
1986	3218	529
1987	2574	599
1988	966	481
1989	1233	424
1990	148	283
1991	985	612
1992	2107	575

*Source: 1992 ESKOM Interconnection Workshop
Paper by ZESCO GM. Robinson Mwanza*

Table 1.5

COMPARISON BETWEEN INDEPENDENT DEVELOPMENT VS REGIONAL PLANS ECONOMIC COSTS - CONSTANT 1992 DOLLAR ESTIMATES US \$ (000'S) IBRD METHODOLOGY					
ITEM	INDEP'DENT DEV	PLAN 'A'	PLAN 'D'	DROUGHT	INTERMEDIATE
CAPITAL COST	\$2,367,635	\$1,620,469	\$1,327,778	\$1,907,226	\$1,792,461
OPERATING COSTS:					
THERMAL COSTS	\$1,326,828	\$992,698	\$1,074,147	\$986,740	\$992,698
HYDRU COSTS	\$1,093,513	\$1,113,306	\$1,107,801	\$1,069,958	\$1,123,511
PURCHASES	\$462,466	\$786,394	\$853,090	\$1,076,130	\$780,944
TOTAL OPERATING COSTS	\$2,882,807	\$2,892,398	\$3,035,038	\$3,132,828	\$2,897,153
UNSERVED ENERGY COSTS	\$48,269	\$892	\$894	\$904	\$960
TOTAL SYSTEM COSTS	\$5,298,711	\$4,513,759	\$4,363,710	\$5,040,957	\$4,690,574
NET PRESENT VALUE @ 10%	\$2,438,593	\$1,947,445	\$1,780,063	\$2,276,421	\$2,075,646
SAVINGS - REGIONAL PLANS VS INDEPENDENT DEV					
CONSTANT US \$	-	\$784,952	\$935,001	\$257,753	\$608,137
NET PRESENT VALUE @ 10%	-	\$491,148	\$658,529	\$162,172	\$382,947

Source: Phase II Technical Report, April 1993
SADC Energy Project AAA3.8.



India*

The case study

1. Information collected for this case study was provided by:

- Ministry of Power
- Central Electricity Authority
- Power Grid Corporation
- Northern Regional Electricity Board
- National Thermal Power Corporation
- Western Regional Electricity Board
- Maharashtra State Electricity Board

Advantage of India as a case study

2. India has an extensive power system with an installed capacity of over 72,000 MW. This total capacity is greater than that in Africa or in South America, and in that context is a substantial potential regional network.

3. The system is operated as five separate grids. International considerations are clearly not a constraint on interconnection. This case study should help to illustrate some aspects of interconnections between power systems generally, without the influence of international relations.

4. As well as internal connections, some of the grids in India have external connections to Nepal and Bhutan. Neighbouring reasonably-well developed power systems exist in Pakistan, Sri Lanka, and Bangladesh, but at present there are no firm proposals to create connections to them.

The power sector in India

5. This section sets out the structure of the power sector in India, summarises the physical assets employed in it, and summarises its operation.

Current organisation

6. The structure of the power sector in India is complex and has grown organically. Overall responsibility is divided between national and state governments. The principal entities and their

* This case study has been investigated by Ian Pope, London Economics Energy.

main relationships are shown in Table 2.1. For simplicity much has been omitted, so as not to obliterate the principles.

7. Major changes are taking place in the organisation of the electricity supply industry. A corporation has been set up, Power Grid Corporation of India Limited, (PowerGrid) to take over ownership and operation of the main transmission system so that it can later act as the "common-carrier" transporter of electricity and dispatcher of all major generating facilities in a power system with both public and private ownership of generating and distributing facilities.

8. Some States are contemplating unbundling of their generation, transmission, and distribution, with possible privatisation of all or part of it. Since the reorganised industry is unfolding pragmatically with only a broad concept of its final form, the present situation is a "snapshot" of a developing process.

State level

9. Fundamental responsibility for electricity supply lies, under the 1948 Electricity Act, with state governments. Under this Act, the State Electricity Boards have the principal responsibility for distribution and security of supply. They operate extensive transmission networks within their states and between them generate over 70% of India's electricity.

10. India has 25 States and a further 7 Union Territories. These are supplied by 18 SEBs, 13 Electricity Departments of State or Union Territory Governments, and a municipal corporation. For the purposes of this report, the expression SEBs will generally be taken to include these other entities.

11. The SEBs are expected to be self regulating, even to the extent of retail price setting, though a minimum return of 3% on assets is in the statutes. This apparent regulatory independence is eroded by the fact that the state governments appoint (and dismiss) the members of the SEBs. SEBs are also responsible under the Act for regulating the licensed private sector operators in their areas.

12. State governments have used their powers to put downward pressure on prices, particularly to the agricultural sector, in response to political imperatives. Prices in general, and agricultural prices in particular, are well below cost. The SEBs are not directly compensated although many receive State Government subsidies to ensure they meet minimum rates of return. This has severely damaged the financial health of many of them. Most still face large levels of debt, despite conversion of some State Government debt into equity.

Table 2.1 Entities in the Electricity Sector			
Entity	Abbreviation	Reports To	Remarks
Generation			
National Thermal Power Corporation	NTPC	National	Develops & operates major thermal plants
National Hydro Power Corporation	NHPC	National	Develops & operates major hydro resources
North Eastern Electric Power Corporation	NEEPCO	National	Specific projects
Neyveli Lignite Corporation	NLC	National	Specific projects
Nuclear Power Corporation	NPC	National	Nuclear power
18 State Electricity Boards	SEBs	States	Develop & operate local generation within states (Total 62% of all India capacity)
13 Electricity Depts. in States & Union Territories	EDs	States/Union Territories	Develop & operate local generation (Total 11% of all India capacity)
5 Private sector Cos		Private (licensed by SEBs)	Develop & Operate generation (4% of all-India)
Transmission & Dispatch			
Power Grid Corporation of India	PowerGrid	National	Develops EHV transmission in all regions (Taking over Regional dispatch)
5 Regional Electricity Boards	REBs	National (with SEBs represented)	Operate Regional Load Dispatch Centres (RLDCs) to co-ordinate inter SEB trade
31 State Electricity Boards & Electricity Departments	SEBs & EDs	States	Develop and Operate HV transmission within State. Dispatch State generation.
5 Private sector Cos		Private (licensed by SEBs)	Local transmission within licensed area
Distribution & Supply			
31 State Electricity Boards & Electricity Departments	SEBs & EDs	States	Distribution monopoly
57 Private sector distributors (5 major and 52 smaller)		Private (Licensed by SEBs)	Licensed distribution monopoly
Regulation and Support			
Ministry of Power	MOP	National	Overall responsibility for power sector
Central Electricity Authority	CEA	National	Executive arm of MOP. Co-ordination of power sector development. Approval of specific projects proposals from SEBs and central sector.
Planning Commission	PC	National	Overall national economic planning. Preparation of 5 year plans. Power sector is 20% of total.
31 State Electricity Boards & Electricity Departments	SEBs & EDs	States	Self regulation of retail prices and security of supply. Regulation of licensed private sector cos
Power Finance Corporation	PFC	National	Additional Financial support for specific projects aimed at more commercial approach by SEBs
Rural Electrification Corporation	REC	National	Support for capital cost of specific RE schemes

Sources: Various papers to Power Sector Reforms Conference, Jaipur, October 1993

National level

13. The Ministry of Power is responsible to the federal government for the power sector in India. The Central Electricity Authority operates under the auspices of the Ministry of Power with responsibility to co-ordinate the activities of the State and National elements of the power sector. Its main vehicle for carrying out its work is an approvals procedure to which all but the most minor projects are subject. CEA approval is needed by both State and central sector entities.

14. Another Federal body with an interest is the Planning Commission. India has traditionally used a high degree of central economic planning, and the Planning Commission co-ordinates the allocation of financial resources to all sectors of the economy, under a series of 5-year plans. The current 5-year plan is the eighth. The Ministry of Power represents the electricity supply industry in negotiating and determining the allocation of the available funds by the Planning Commission. On average the power sector has received about 20% of funds allocated to infrastructure development. As India moves towards a market economy, the power of the Planning Commission is being eroded.

15. Power generation is carried out by central sector bodies as well as the state enterprises. These central sector bodies sell power under contract at tariff rates to SEBs. The output of individual stations is often shared between more than one SEB. Central sector generators produced about one quarter of the total Indian generation for public supply in 1992/3. They include the National Thermal Power Corporation (NTPC), the National Hydropower Corporation (NHPC), the nuclear plant, and a variety of other bodies.

16. The national government also controls PowerGrid, a corporation formed in 1990 to take over the EHV transmission of the central sector generators, and to develop this towards better regional grids, and eventually a national grid.

17. In 1964, to expedite shares of central sector power station output and to encourage trade between the SEB's, the central government set up regional load dispatch centres. These were run under the auspices of the CEA by Regional Electricity Boards (REBs) on which the SEBs were represented. Later, when it became apparent that there could be economic advantage in exchanging power and energy between adjacent REBs, steps were taken to set up interconnections between REBs.

18. The co-ordination of the output of central sector stations and the organisation of the trading of any surpluses between SEBs is carried out by Regional Load Dispatch Centres. These are controlled by Regional Electricity Boards who operate under the aegis of the CEA, but with representation of member SEBs. There are five such regions.

19. In addition there are two bodies providing financial incentives. Power Finance Corporation was set up in 1986 to raise financial resources for investment in power projects that were of sufficient priority to justify funding outside state and central budgets. PFC funding is available only to utilities that have agreed to implement a plan of both operational and financial actions and endorsed by their state governments directed at making the utility commercially viable. The Rural Electrification Corporation provides financial support for rural electrification projects.

20. The development of renewable energy resources is the responsibility of a separate ministry, and is aimed principally at de-centralised production in rural areas.

Private sector

21. Prior to the establishment of the SEBs, most of India's power sector was in private sector hands. The Act allowed the private sector to continue under licences from the SEBs. Over the years many of these licences were not renewed, and the vast majority of the sector moved into the public sector. There are two groups of exceptions to this generality.

22. In some of the larger cities significant private sector entities continued in generation and distribution. The majority are vertically integrated entities with generation as well as distribution, though Bombay Suburban is only now entering the generation market, having mostly contracted its power from Tata. Private sector generation accounts for about 4% of India's total. No private sector power is sold across SEB boundaries. The other main private sector entities are the fifty or so small licensed distributors.

23. Recent developments are encouraging independent power generators to come into the market to supply power to the host SEB under contract. An elaborate system of guarantees is being put in place to encourage IPP developments, and several are near the point of contract signature, and may have done so by the time this report is circulated. It is difficult to assess the size of this development but several thousand MW are the subject of active discussion.

Physical characteristics and generating resources

24. India is approximately diamond-shaped, 2800 km from the Himalayas in the north to the tip of the peninsula in the south, and 2000 km from its border with Pakistan on the Arabian Sea in the west to Bangladesh on the Bay of Bengal on the east. In addition there is the north-eastern region of India, which is almost separated from the rest of the country by Bangladesh.

25. The northern boundary is the Himalayas, except where the small nations of Nepal and Bhutan occupy the sections of the India-China border. Rivers that rise in the Himalayas feed the Ganges river and have vast undeveloped hydro-electric potential. The hydro sites suffer from

very difficult geological conditions and this, together with the great distances separating them from the more densely populated areas of India, has retarded their development.

26. The overall generating capacity is 72,000 MW, and the energy supplied in 1992/3 was in the order of 220,000 GWh. The average availability of the plant was 58% and the maximum demand actually met was about 49,000 MW. The main causes of thermal plant unavailability, which is a little higher than that in most industrialised countries are set out in Table 2.2.

Table 2.2 Thermal Plant Unavailability by Cause	
Cause	Unavailability as % of rated capacity x 8760 hours
Planned Maintenance	10%
Forced Outages	14%
Output Restrictions	9%
Auxiliary Consumption	10%
Spinning Reserve Allowance	5%
Hence Peaking Capability	58%

Source: Administrative Staff College, India

27. The principal characteristics of each regional grid are set out in Table 1.3. The Western and Eastern regions have limited hydro-electric resources.

28. Table 2.3 also sets out an indication of the plant/load position in each of the regions. Even when a surplus is indicated, plant margins throughout India are tight and shortfalls do occur everywhere from time to time.

Regional grid	Installed Generating Capacity MW	Proportion of hydro	Plant/demand position*
Northern	21,238	30%	Energy and capacity shortfall
North Eastern	1,147	42%	Energy and capacity surplus
Western	22,225	12%	Small capacity shortfall
Eastern	10,217	16%	Energy and capacity shortfall
Southern	17,492	48%	Energy and capacity shortfall
All India	72,319	28%	

Source: PowerGrid

Note*: Consultant's indicative estimates only -- actual plant/demand position will vary according to plant availability and hydraulic conditions

29. The shortfall in generating capacity is not uniformly distributed through the different regional grids. Those with predominantly thermal generation need to "back down" their generation during the overnight low load period. This unused generating capability could be used by the regions with a greater proportion of hydro to alleviate their energy shortfalls. Table 2.4 shows the historic energy shortage patterns as a percentage of the energy actually supplied.

Region	1984/5	1985/6	1986/7	1987/8	1988/9	1989/90	1990/1
Northern	14.0	10.7	9.5	11.3	5.9	5.8	5.4
Western	0.7	1.4	4.2	4.9	2.6	2.6	3.6
Southern	Surplus	9.3	11.0	16.9	13.8	13.3	10.9
Eastern	17.3	13.8	17.7	12.2	11.6	15.0	18.5
North - Eastern	Surplus	3.6	6.2	4.8	3.2	3.0	4.6
All India	6.7	7.9	9.4	10.9	7.7	7.9	7.9

Source: Tata Energy Research Institute, India

30. The demand met by the generating system is suppressed by a number of factors:
- overt power rationing through customer disconnections;
 - lack of connections to communities and individual premises, particularly in rural areas;
 - restrictions in the transmission and distribution system; and
 - consumer (and potential consumer) reaction to poor supply reliability.
31. The second and third points represent competition for resources to increase generating capacity, and improve interconnection capability. Investment in one part of the sector will have (sometimes counterintuitive) effects on another.
32. India has considerable reserves of coal located in West Bengal and eastern Maharashtra, the latter of sufficiently high ash content and low calorific value that its exploitation is mostly restricted to mine-mouth generation of electricity. Some of the Maharashtra coal is shipped to generating stations on the west coast, where more than half its price is represented by transportation costs. The Domodar Valley Corporation has been exploiting the West Bengal coal resource for the production of electricity to supply Calcutta. More recently, NTPC has been producing electricity from mine-mouth plants in east Maharashtra.
33. The largest load centres are Bombay, on the west coast, Calcutta and Madras on the east coast, and Delhi in the north.

Transmission

34. The electricity sector supplied only the urban areas until 1948. The SEBs that were then set up began the expansion of electric supply into the rural areas. The development of high-voltage transmission was limited before 1948 but increased rapidly thereafter. Higher-voltage transmission at 400 kV was started in the late 1960s with the development of the east-Maharashtra coal-fired generation. These developments were strictly based on the requirements within states, except where an obvious economical interest served to promote an inter-state tie. A National Grid had been contemplated by CEA but significant inter-state transmission was not pursued until the central government created the Central Sector Generators under an amendment to the Electricity (Supply) Act passed in 1976.

35. Thus the transmission network within each grid consists of each self-contained SEB transmission system with some inter-state connections and a "superimposed" system of radial feeds from large central sector plant.

36. There are some inter-regional interconnections within India. There is a 500 MW back-to-back DC interconnection installed near Agra, Uttar Pradesh, in the Northern Region is a 400 kV line to Gwalior, Madhya Pradesh, in the Western Region. Currently this tie operates at about 45% annual load factor. Others are under construction - see Section 4.

37. Two 400 kV lines interconnect Chandrapur generating station in eastern Maharashtra, which is in the Western Region, with Ramgundam, Andhra Pradesh, in the Southern Region. Due to the difficulties experienced with frequency-control, this tie can only be used to serve loads in northern Andhra Pradesh when power has to be sent south. A back-to-back DC tie is to be installed at the Chandrapur end of this line to provide a 2-way interconnection. Another interconnection between these two regions is planned between southern Maharashtra and Karnataka. There are innumerable interconnections at the lower transmission voltages between neighbouring SEBs. These also exist between neighbouring SEBs in adjoining regions, but these are of limited use since the regions cannot be synchronised.

Operation and grid discipline

38. To students of grid system operation, the problems of grid discipline in India are well-known. It is not part of the remit of this report to analyse in detail the reasons for grid indiscipline, nor to propose solutions. Nevertheless, grid indiscipline is important to the study of interconnecting regional networks insofar as it impacts upon the ability of the regional grids to interchange power with their neighbours.

39. In India the responsibility for matching production capacity to demand lies primarily with the SEBs. To meet their demand SEBs have access to their own generation together with contracted portions of central sector generators. The SEBs are interconnected with each other in Regional Grids. PowerGrid also provides EHV transmission from the Central sector power stations to individual SEBs. To some extent this supergrid network can also act as the transmission network to exchange power between the SEBs.

40. The co-ordination of trade at the regional level is the responsibility of the Regional Load Dispatch Centre (RLDC). These are currently operated by the CEA, though the SEBs are represented on the REBs who take responsibility for the regional load dispatch centres. Their role is to organise the shares of central sector plant according to the contracts, and to arrange the trading of any surpluses. They have no financial involvement, other than to calculate what the SEBs owe each other as a result of the trade each month. They do not handle the cash.

41. There are no contracts to cover the organisation of inter-SEB trade. As the concept is generally of offering for sale unwanted shares of central sector plant, the price of the trade is determined largely by the appropriate central sector tariff.

42. Because of the chronic shortfall of available generating capacity in practically every SEB in India, the degrees of freedom available to the RLDC dispatchers are limited. All thermal plant is connected to the system so long as it is available for service. Hydro plant is operated by the SEBs in accordance with the water availability. During a typical day there are two types of dispatch decision to be made by the RLDC. During the night, if there is any surplus capacity, decisions focus around which thermal plant should be "backed down". During the day, dispatch decisions focus around ensuring that each SEB sheds sufficient load so as not to try to draw more than their allotted share of central sector power. RLDCs do not directly dispatch SEB plant, this is an SEB responsibility.

43. The principal reasons for grid indiscipline can be explained by examining each of these dispatch decisions and their execution in turn.

44. **Off-peak operation:** Particularly in the Eastern and Western regions, with their predominance of thermal power, all the generating capacity (including the share of central sector plant) often exceeds off-peak demand. The function of the regional dispatch centre is first of all to offer this surplus output to other SEBs that may require it within the region. If it is taken up by the other SEB, the price will be the central sector tariff price for the particular plant.

45. If all SEBs' demand is satisfied, the dispatch decision centres around which of the thermal plant should be "backed down" or reduced in output. Costs within the region will be minimised if the plant backed down is that with the highest short run marginal cost. That will normally be the older and smaller plant belonging to the SEBs rather than the larger, newer and more efficient plant belonging to the central sector. There are a number of disincentives to the SEBs (and to some extent the central sector plants) to obey these dispatch instructions. These include:-

- The SEB is charged a single price per kW for power drawn from the central sector stations for the central sector generator to recover both his fixed costs and his short run marginal costs. Thus the perceived cost to the SEB of using central sector power is significantly higher than the short run marginal cost of maintaining generation at his own plant.

- In order to encourage better plant availability performance, individual staff members in central sector and SEB power stations are paid an incentive bonus related to the load factor of the plant. Thus, to accept backing down instructions reduces the income of individual employees in the power stations concerned. The individual incentive schemes are being modified to reward availability rather than load factor. While this has greatly reduced the level of incentive, some incentives still remain.
- There has been an attempt to introduce an element of two-part tariff between central sector plant and the SEBs. The implementation of this is frustrated by the fact that in most states no metering exists to be able to differentiate the time of day at which power is drawn and therefore no mechanism by which the power and energy elements can be charged to individual SEBs. This means that, although the central sector charges REBs on the basis of a two-part tariff, the REBs who allocate the costs have to pass the costs on to SEBs as a single unit price based on the average price to the REB.
- It is not clear that the basis on which SEBs calculate their marginal costs of generation is compatible with those on which the two-part tariff for central sector plant is calculated. Similarly, there is no certainty that SEBs within a region calculate their short run marginal costs on compatible bases.

46. These factors produce a reluctance on the part of power station operators to "back down" and this leads to periods of very high frequency operation during off-peak times, often as high as 51.5 Hz or 52 Hz.

47. **On-peak operation:** During peak times SEBs are under considerable pressure from their customers to maintain supplies. Because virtually all of them have insufficient generating capacity to meet consistently the demands placed upon them, they have to engage in routine load shedding by disconnection of customers. The RLDC has a responsibility to ensure that individual SEBs do not "over draw" on the contracted amounts from central sector generators, and therefore issue instructions to SEBs as to the extent to which they should disconnect their customers from time to time.

48. As might be imagined, SEBs have considerable incentives not to implement these instructions. These include:

- Considerable political pressure from their sponsoring state governments who appoint SEB members and whose votes depend partly on ability to meet demand for electricity.

- subject to personal physical attack and abuse as they try to implement the instructions.

49. These factors tend to push the frequency right down during peak times, sometimes to below 48 Hz. The whole situation is exacerbated because, fearing the deleterious effects of these wide frequency swings on their plant, power station managers disable the governing mechanisms on their plant to a significant extent so that the whole methodology of system control is put in danger and there is no real automatic control of plant. This means that, even during the middle of the day when load and generation are reasonably in balance, the disablement of governors means that frequency control is still very uncertain.

50. The frequency range regularly experienced in India is 2 Hz either side of nominal. In UK the frequency range is 0.2 Hz, and in the UCPTE and the North American grids, less than 0.02 Hz.

Inter-regional connections

51. This section examines the physical interconnections that exist between the regions, those that are planned and those that are under construction. The technicalities of interconnection are briefly discussed. The section then analyses how those interconnections are used, how the traded flows are agreed and how the benefits are shared. It also looks at the value of, and the constraints on, increased use of the links, and the construction of further links.

Physical connections

52. The main inter-regional links are the DC ones. Those that are in existence or under construction are set out in Table 2.5 below.

Between regions	Link capacity MW
South - West	1000
North - West	500
East - South	500
North - East	500

Source: PowerGrid

53. In addition, there are a number of lower voltage AC links. There have been attempts to use these to synchronise between regions but the difficulties of frequency control do not allow sufficient control over the power transfers. These AC links are used to arrange radial supplies.

54. International interconnections play a minor role in India. No ties exist with its large neighbour Pakistan, nor with the smaller Bangladesh, whose territory almost isolates the North-Eastern Region from the rest of the country. There are local connections at distribution voltages with Nepal and a 132 kV connection is under construction that will be used for local support to the Nepalese and the Bihar SEB. Some power is imported from Bhutan by the Assam SEB.

Synchronous or asynchronous connections

55. The previous section outlined some of the principal factors leading to the lack of discipline over the control of frequency in the various Indian Regional Grids. This section looks at the principal technical issues covering the interconnection of power systems with particular reference to grid discipline. It explores whether improved grid discipline is a prerequisite for increased inter-regional trade and discusses the relative merits of synchronous and asynchronous connections.

56. **AC Links:** In AC power systems in India, as elsewhere, all the generators connected to the system rotate at the same speed and in synchronism. All the generating sets are equipped with a governor which is a control mechanism designed to keep the turbine operating at a constant speed. As the turbine slows down through the imposition of more load, the governor senses the drop in speed and increases the steam (or, in the case of hydro-electric plant, the water) supply. Thus, provided enough generators are connected to the network, supply and demand are automatically in balance.

57. When two systems are not interconnected, they will run at different speeds and will not be in synchronism. If an AC connection is made between the two, power will flow through the connector to make the speeds of the two systems identical. If the speed of one is markedly slower than the other a large amount of power will flow into the slower system. If the connection is a relatively weak one, that is its load carrying capability is small compared with the size of the two systems it is interconnecting, the amount of power it is required to carry to bring the two systems into synchronism may exceed its carrying capacity. In this case the systems will break synchronism, and electrical instability will result. The link will be broken and one or both of the systems may suffer electrical collapse. Very close control of the outputs of the power stations in the two networks can overcome this problem.

58. **DC links:** In DC links the AC power is rectified into DC and smoothed and is transferred across the link in DC and then converted back to AC through an inverter station. The transfer of power is controlled by the electronics of the convertor station and takes place

independently of the frequency of either AC system. This means that controlled quantities of power can flow between two asynchronous AC systems with no need to apply tighter control to the internal workings of either.

59. The convertor stations are expensive, but DC lines are cheaper than AC lines per MW kilometre of transmission capability. Thus a long distance DC line might be cheaper than equivalent AC line, but on short distances DC will be considerably more expensive. In India very short-back-to-back DC links are under construction to enable power to be transferred between adjacent regions without the need to synchronise.

60. Whilst DC links do allow the transfer of power between regions without the need to synchronise, this very fact reduces their usefulness for providing mutual spinning reserve. This is because the link is incapable of responding to the frequency changes resulting from a sudden generator loss incident in one of the networks. In the case of the Indian grids at the present time with their chronic shortfall of capacity, spinning reserve is not usually an operational consideration, as there is insufficient capacity to provide it and therefore the concept of one region providing emergency or spinning reserve to another is not a realistic one. Table 2.6 below summarises the relative characteristics of DC and AC links.

Parameter	AC	DC
Control	Tight load and frequency control in interconnected networks. Operating cost implications	Link power flow is set electronically and independent of conditions in either interconnected network.
Frequency	Requires synchronism	Allows independent operation.
Spinning Reserve	Automatically supports deficient area, within capability of link. sudden changes in generation condition could trip link (if relatively weak) and risk collapse in one or both grids.	Can be programmed into control electronics if desired. Self limiting therefore less risk of grid collapse.
Voltage control and reactive power	Can be transferred. Needs careful control in both networks	Cannot be transferred. Converter stations require reactive power for excitation.
Capital and operating cost	Converter stations expensive, lines cheap. Can be cheapest option for very long distances. Relatively high maintenance. Modest losses	Cheaper for all but the longest connections. Modest losses
Reliability	High, can be improved by use of bi-polar links.	Very high

Source: LE Energy

61. **Applicability to regional interchange in India:** Attempts that have been made in the past to establish inter-regional connections through AC links have failed because of the inability to control the power flows. This is hardly surprising. Even in a very well regulated network, the interconnection of two systems, each exceeding 10,000 MW in size through a link of less than 200 MW capacity would require extremely tight frequency control for there to be any effective control on the transfers at all.

62. More recently, a DC link has been established between the Western and Northern Regions, and this has been used fairly extensively to transfer power from the Western region to the Northern region during off-peak periods when generation in the Western region would otherwise be "backed down". This energy is used by the Northern region to displace hydro production during off-peak times and thus to enable it to produce more during the peak times. The link operates at an average 46% capacity factor, thus transferring about 2,000 GWh through the year. During this period the grid discipline in both the Western and Northern regions has not been any better than in previous years. Grid discipline has thus not been a strong constraint on inter-regional trade.

63. Asynchronous trading has also taken place through "radial feeding" which involves disconnecting some of the consumers in the recipient region and re-connecting them to the donor region. As this is a relatively cumbersome and time-consuming process it cannot effectively be used for sorting out day and night trading opportunities but rather to overcome local transmission problems or to cover wet or dry hydro-electric periods. Clearly, spinning reserve cannot be transferred through this mechanism.

Organisation of inter-regional trade

64. The REBs were set up to organize *inter alia* the inter-regional movements of energy and power. Having sorted out the shares of central sector plant between the SEBs within the region, and dealt with the trading of any surplus generation, the RLDC would be in a position to seek help from a neighbouring RLDC if it had a deficit, or offer to trade if it had a surplus.

65. Currently all RLDCs face deficits of energy and/or capacity day after day with almost no opportunity for economy interchange outside the regions. However, those regions with limited amounts of hydro plant do have surpluses at off-peak times. In the absence of inter-regional trade, these surpluses are dealt with by backing down the thermal generation (albeit reluctantly).

66. As there is no rigid formula laid down to cover inter-regional trades, the actual mechanism will depend on the RLDCs involved and the particular circumstances of the trade. As

an example, the process used between the Western and Northern regions using their 500 MW DC link is:

- The RLDCs examine their plant/demand position and schedule the generation (and load shedding) to meet demands within the region.
- If there is a surplus at any time, a schedule of surpluses at different times is drawn up and transmitted to the other RLDC. The price quoted will be the tariff from the appropriate central sector plant.
- The recipient RLDC decides if it wants to trade. In the unlikely event that it also has surplus power, it will quote its marginal central sector plant, and if there is a price difference, a trade can be agreed. If it is in deficit, the price is the most expensive central sector plant.
- Once the trade is agreed, both the RLDCs independently inform PowerGrid (operators of the DC link) of the agreed trade. If both statements agree, Powergrid implement the trade. If the statements disagree, no trade is implemented and the RLDCs must re-negotiate.
- As the link is DC, power flows at the agreed rate regardless of the frequency on either grid.
- The SEB(s) whose surplus was traded, or who received energy is informed, and the charge owing calculated, at a price halfway between the two quotes. It is the responsibility of the SEBs to deal with the cash transfers between them.

67. Power flows between regions also take place through radial feeding. As with DC, this does not require synchronism. An agreed amount of load is first disconnected from the recipient region, and then reconnected to the donor region. This is a cumbersome process and requires disconnection to effect it. It is therefore unsuitable for day to day operation and is used for longer term trades. As with the day-to-day trades, there is no firm basis laid down for the trading, and agreements are on an ad hoc basis.

68. Table 2.7 shows the historic trade in energy expressed as the net energy exchanged. As the trade between each pair of regions tends to be unidirectional, these figures can be considered as fairly representative of the total gross volume traded.

Region	1988/9	1989/90	1990/1	1991/2	1992/3
Northern	260	234	565	946	432
Eastern	(283)	(333)	(923)	(823)	(412)
North - Eastern	0	0	0	(51)	(57)
Southern	(1,259)	(1,009)	(499)	(187)	(244)
Western	1,282	1,108	857	120	281

Source: PowerGrid Corporation, India

69. With total all-India generation in excess of 300,000 GWh, the volume of inter-regional trade is less than 0.5%.

Benefits of interconnection

70. Although the regional grids in India are chronically short of capacity, these shortfalls do not all occur simultaneously and there are occasions when some grids may have energy surplus whereas a neighbouring grid has an energy shortfall. This is because in most regional grids in India the existence of hydro electric capacity allows at least some storage of electrical energy (by holding on to water in the reservoirs when excess thermal energy is available). Table 2.8 shows the amount of surplus thermal energy that was "backed down" in off-peak times in the different regions.

Region	Backing Down 1992/3
Northern	2,786 GWh
Eastern	---
North-Eastern	---
Southern	265 GWh
Western	5,699 GWh
Total	8,640 GWh

Source: PowerGrid Corporation, India

71. With the overall generation in India standing at about 220,000 GWh, this means that about 4% more energy could be generated from the existing plant, if it could be "stored" from the night to the day. The surplus arises in the East and the West where there is insufficient hydro capacity to effect rescheduling to allow this power to be used. If it could be transferred to the South and the North, some of it could be used to reduce overnight hydro generation and increase supplies available during the day.

72. Therefore, interchange of electricity between regional grids can save money and can reduce the overall amount of power rationing required in the regional grids. In its report (*India: Long Term Issues in the Power Sector*) prepared in 1991, London Economics studied the potential benefits that could be obtained through greater trade between the Northern, Southern and Western regions. They concluded in that report that considerable savings in unsupplied energy and in money were possible through the greater use of regional trade. The results of that study have been simplified in Table 2.9, which shows the amount of unsupplied energy that could be reduced by volumes of trade up to the capacity of the existing interconnectors, and if interconnection capacity was increased to such a level as it was no longer a constraint on trade.

Regional Grid	Northern	Western	Southern	Three Grids
Base case (no change)	1,160	850	7,745	10,256
Inter regional trading to existing tie line capacity	721	787	3,101	4,609
Unconstrained trading	1,022	413	190	1,625

73. Included in the savings are some 500 GWh arising solely from the improved grid discipline which we considered as an essential prerequisite to substantial inter-regional trading.

74. Table 2.10 outlines the financial savings that can result from increased inter-regional trade. The figures represent the overall change in generating cost in each region, and the total is the net saving to all regions arising from trading. In order to make the trade work, the benefits will have to be shared equitably.

Regional grid	Northern	Western	Southern	Three Grids
Inter regional trading to existing tie line capacity	2,097	(4,186)	9,168	7,079
Unconstrained trading	730	(5,476)	14,990	10,244

75. The figures in the table include Rs 1,222 million arising solely from the improved grid discipline we assumed as a prerequisite to increased regional trading.

76. The numerical work in the London Economics report was based on the system in India as it was in 1989/90. It is beyond the scope of this study to repeat that work, but we do not see any major changes that have taken place that would reduce the benefits of interconnection. Furthermore, we have not been able to calculate figures for the other two regions, but we believe that these would be in the same order of magnitude.

77. In the following sections we try to analyse the opportunities and achievements against a standard classification of the benefits that can arise from interconnection.

78. **Provision of mutual emergency supplies:** This category normally envisages utilities for systems with an adequate plant margin and which have been planned as independent systems, helping each other out in emergency situations either through radial feeding or through synchronisation. This is not done as a routine, but remains an option in emergency. The existence of such an emergency trading potential can allow either or both networks to reduce their reserve margin when planning plant capacity.

79. As none of the regional grids in India has the luxury of excess capacity over demand, the question of one being able to put any credibility on importing from another in emergency is not a realistic one. Furthermore, as none of the grids achieve their plant installation targets, the concept of savings through reducing reserve margin is also unrealistic.

80. While the concept of savings in plant capacity through the potential for emergency reserve is unrealistic, some of the radial feeds could be considered as emergency supplies. However, their existence has not reduced the plant installation programme and represents only a small volume of inter-regional trade.

81. **Opportunity trading:** Most of the trading that does take place across the DC links in India can be considered opportunity trading. There is no real formal structure, and the detailed mechanisms differ between RLDCs. By common consent the price often fixed is halfway

between the average central sector purchase prices or the marginal central sector prices in the two regions effecting the trade.

82. In the opportunity trading mechanism, strictly speaking, the RLDC agrees the trade with the adjacent RLDC on behalf of particular SEBs. By implication, it is one SEB trading its surplus share of central sector plant that may arise from time to time to another SEB in an adjacent regional grid. Although the deal is struck by the RLDCs and the invoice calculated by the RLDC, the actual cash transaction is between the two SEBs. We were not able to ascertain how good the payment discipline was for these trades. Payment discipline is known to be bad between SEBs and the central sector power stations.

83. **Firm energy:** At present none of the trades that exist between regional load dispatch centres can be described as firm energy. PowerGrid and NPTC would like to arrive at the situation where central sector power stations can be constructed to supply SEBs outwith the bounds of the regional grids. They claim that they can establish considerable long term cost savings in doing this. PowerGrid and the CEA claim that full regional interconnection could produce savings in capacity requirements equivalent to 10,000 MW by the end of the eighth plan, i.e. at the end of 1995. This is of course a theoretical figure because it would not be possible to construct the links in that timescale anyway.

84. **Load and fuel diversity:** This category of benefits arises through there being a difference in the fuel availability, or in the load pattern between the two grids. The trading advantages can be taken through a formalised schedule of trades or through an opportunity trading mechanism.

85. In India, most of the inter-regional trades that do take place, arise from the different proportions of thermal and hydro in the different regional grids. The pattern of daily demand variations between the regions seems to be small. Most have a flat load curve with an extended peak from the start of the working day, well into the evening. This means that there is little load diversity between the regions. While the Eastern and Western Regions have the majority of the cheaper Indian coal, the power stations burning it are rarely backed down, other than overnight, and the trade in backed down capacity is against the opportunity to store water in hydro reservoirs rather than to exploit lower cost fuel supplies.

86. Occasionally, during heavy rainfall periods there may be a short term glut of hydro energy from one of the hydro rich regions. This will also be dealt with by the opportunity trading mechanism, and does not amount to a significant volume of trade on an annual basis.

87. **Economies of scale:** When power networks interconnect and the interconnections between them are relatively strong, the members of the interconnection can consider using unit sizes appropriate to the whole interconnection rather than to the individual utilities. This means

they are able to achieve potentially considerable economies of scale. In India the regional grids themselves are already quite large compared with any likely unit sizes and therefore further savings arising from economies of scale through interconnection are not likely to be large.

88. Access to lower cost resources: Currently, NTPC and other central sector generators plan their capacity developments on a regional basis. In discussions with the National Thermal Power Corporation (NTPC) we were told of a number of potential mine mouth projects in the Eastern Region and the Western Region that could be developed for export to the Southern or Northern Regions. The implication was that this would be cheaper than developments within the Northern or Southern Regions relying on coal transportation.

89. As the Maharashtra State Electricity Board (in the Western Region) is near to signing a contract for a LNG fired combined cycle gas turbine plant, presumably this is economic compared with burning Indian coal. As LNG is not site specific for its economics, it seems unlikely that large scale mine mouth coal fired developments with long distance transmission will compete with CCGT plant sited near load centres. This factor would suggest that large scale savings through constructing thermal plant for transmission across regional boundaries are unlikely. However, we should stress that the comparative costs have not been reviewed in detail in this study.

90. A number of major hydro-electric sites in the Himalayas have been identified as being economic, and could justify the long distance transmission. They lie within the northernmost states of India and in Nepal and Bhutan. Some may be economic enough to support full private sector finance and exposure to development risk. So far, public sector development of these resources in India seems to be capital constrained. In Nepal and Bhutan development is also constrained through the reluctance of those governments to become over dependent on trade with India. They fear that once they have sunk their costs, they will face downward pressure on prices, and difficulties in enforcing payment. The same factors may affect the state governments' attitude in India, to development of large state generation projects with most of the power being exported to other states.

Proposed reforms

Concepts

91. There has been a growing recognition that the complex structure of the power sector with its divided reporting and responsibility, needs some reform. The reforms have been driven by two main considerations:-

- the desire by the federal government to mobilise more resources into generation by involving the private sector; and

- the view developing in an increasing number of state governments that the power sector in the States need to be on a better financial basis.

92. These factors are coupled with a general trend in economic policy to move away from central economic planning and a high degree of economic regulation of industries. As a result, the pattern for reforming the electricity sector is emerging.

93. In response to a shortage of government-sourced development capital the bulk generation of electricity has been deregulated and is open to the private sector, both local and foreign, with no limits on foreign participation. To further facilitate the development of independent power generators, the transmission system has been separated from the generation agencies. It is intended to give non-discriminatory access to all users.

Generation

94. Privately-owned and operated power stations have existed in India since 1910, if not earlier. After 1961 their development was discouraged but those with operating licenses were allowed to continue. They are now being encouraged to expand, and Tata Electric, which generates power for sale by the two distributors that serve Bombay, has already added a 500 MW steam set to its production facilities. Other private operators are being actively encouraged to enter the field and Enron, a US organisation, is amongst a number who are actively pursuing contracts with SEBs.

Transmission

95. It is intended that PowerGrid become the owner/operator of a common-carrier trunk transmission system formerly owned by the central sector generators and the dispatcher of the major generation plants. It has a remit to develop the transmission into stronger regional grids, and to foster interconnections between the grids. Ultimately the long term aim is for a national grid in India.

96. PowerGrid has already taken over all the transmission lines previously owned by NTPC and all their 400 kV substations that are not associated with their generating stations. They have also taken over the RLDC in Bangalore and will take over all the other regional dispatch centres from CEA within the next two years, thus completing their control of all inter-regional power transfers.

97. PowerGrid intends to provide facilities for the trading of bulk electricity. At no time will it become the owner of any energy but it will offer a completely transparent exchange mechanism in which buyers and sellers will know what power is flowing and the value or price

of energy. A consultant has been appointed who, it is expected, will report in a year on the precise mechanisms of this operation. It seems unlikely that a spot market bidding system will be recommended. The consultant's remit includes design of the process by which additions to the central transmission system will be effected and paid for. PowerGrid have already said that optimisation of regional grids will have first priority in setting intra-regional trade. Inter-regional trade will then be scheduled.

98. The establishment of PowerGrid was seen as an essential first step in securing the interest of the private sector in bulk generating plant. Enron, which is developing a 2000 MW CCGT project in Maharashtra, appears to have entered the process by insisting on an agreed price and other conditions with the SEB. This is almost certainly because being located near Bombay they will be unable to offer much of their production outside the state, since PowerGrid owns no transmission facilities near the western side of Maharashtra.

99. One of the problems of intra- as well as inter-regional trade is the paucity of on line information on flows, and the remoteness of the RLDCs from the plant. Dispatch instructions are all relayed to plant operators "second-hand".

100. PowerGrid hope to rectify the current situation by having all the major power flows now monitored by the RLDCs communicated to their national load dispatch centre (NLDC). The RLDCs would not just monitor the flows as they do now but they would exercise remote control of the load controllers between the regions. Being able to see the national picture, the RLDC would be able to suggest the optimum economic dispatch of the generating resources.

State level

101. At the state level, some governments, notably those in Orissa, Madhya Pradesh, and Maharashtra, have been actively considering the re-structuring of their electricity sectors. Legislation no longer prohibits new private sector involvement. Unbundling of generation, transmission, and distribution are key elements. So too is the creation of an independent regulator.

102. State governments may go as far as to privatise their existing facilities, and certainly most are actively pursuing independent power generator contracts. It is not yet clear what is to be done regarding the extensive and expensive cross subsidy to the agriculture sector.

Environment

103. Environmental pollutants include the acid rain gasses and carbon dioxide, which is a global rather than specifically Indian environmental problem. Indian coal has a high ash content, and ash disposal in a significant consideration.

104. Table 2.11 below sets out the changes in emissions of the principal pollutants resulting from increased trade between Northern, Western and Southern regions. The figures are drawn from the London Economics' report *India: Long Term Issues in the Power Sector, 1991*, and apply to the year 1989/90.

Table 2.11 Changes in emissions, relative to base case, for different trading volumes Thousand Tonnes				
Pollutant	Ash	SO₂	NO_x	CO₂
Inter regional trading to existing tie line capacity	572	22	23	5,387
Unconstrained trading	572	27	30	7,598

105. Although the efficiency of fuel use increases as a result of trading, the effect of reducing the unsupplied energy, and hence increasing the total amount of generation from thermal plant, means that emissions of pollutants increase.

106. Ultimately, when the system in India moves away from the chronic plant shortage, trading will have only a small effect on unsupplied energy (because there should be very little) and the increased efficiency should lead to reduced emissions as a result of trading.

Summary and conclusions

107. This section summarises the principal findings of this case study under the case study checklist headings, and then draws conclusions for the study of networks in general. These conclusions are divided into two categories: factual conclusions and judgemental conclusions.

Background

108. India has a large power sector at 72,000 MW. This is larger than the continents of Africa or South America. It is planned and operated as five separate grids, four of them larger than most countries' systems. In the country as a whole, 28% of the capacity is hydro and the rest is thermal. With availability taken into consideration, the plant is able to meet a maximum demand of 49,000 MW.

109. Over 96% of the sector is in the public sector, with virtually all the distribution, and three quarters of the generation in the hands of the States, and the EHV transmission and one quarter

of the generation in the central sector under the federal government. The State entities are self-regulating.

Benefits of existing connections

110. The smaller AC links between the regions were installed for a variety of reasons. Local support of networks near the regional boundaries was one reason for a number of the lower voltage links, and the concept of emergency supply undoubtedly drove some of the decisions. Some of the links existed between adjacent SEBs before the regional grids were established.

111. In practice, the inter-regional links (operated asynchronously as described above) were used for two main purposes:

- Radial feeds to supply specific areas of one SEB from an adjacent SEB in a different region. This is done by resynchronising customers to the donor region, and not by connecting the networks together.
- The DC links are used to transfer off-peak energy from predominantly thermal regions to predominantly hydro regions, where they can be used to displace hydro energy which can then be used at peak.

112. There is no formal structure for any of the inter-regional trades, and therefore they could all be regarded as opportunity trading.

113. Because of the insecurity of the supply in all regions, no region will regard the opportunity for emergency import from an adjacent region to have any value in displacing the need to install new capacity.

Contractual basis for trading

114. There is no formal contractual relationship to cover the trading between regions in India. The primary function of the Regional Load Dispatch Centres is to coordinate the sharing of output from central sector plants between State Electricity Boards. Insofar as there is any excess supply within a region, the RLDC is able to try to negotiate on behalf of its member SEBs, trades with the adjacent region. The exact mechanism for trading varies from region to region, but all are based on the concept of average or marginal central sector plant tariffs, and the price struck is usually set halfway between the bid and offer prices. As most trade is from a region that has some surplus at the time, to another region that has a deficit, the recipient region is expected to quote its most expensive central sector plant. The selling region does not expect to get some form of distress price for the sale.

115. Because all the trades are opportunity trades, there is no fixed length for the contract, and agreements are usually measured in hours or fractions of an hour, rather than days, weeks or months. The agreement is struck between the RLDCs on behalf of the SEBs, and the SEBs are expected to make the actual payments. The DC links are equipped with advanced metering systems capable of registering consumption at different time of day and so on. Other connections, including the connections between the SEBs within the region, are usually only equipped with energy metering. This mitigates against the use of time-of-day pricing for the intra-regional and inter-regional trade.

Operation

116. The operation of the existing linkages depends on the type of trade. Radial feeds are agreed between the adjacent State Electricity Boards, with the REBs being involved informally in the discussions. Once the trade is agreed, the recipient REB isolates the appropriate part of his network and then reconnects it to the donor REB. Because this is a cumbersome process, these trades usually take place over longer term periods. The physical nature of the trade means that the customers who have been transferred experience approximately the same security of supply as customers in the host SEB. Grid discipline is not relevant to this kind of trade. We were not able to ascertain with any certainty whether payment schedules were met.

117. In the trades over the DC links, the opportunity trade is agreed between the RLDCs, and then each RLDC informs PowerGrid (the operator of the links) of the agreed trade volume. If the two pieces of information agree, PowerGrid implements the trade. Because the operation of the link is not within the hands of the SEBs, and because the flows in DC lines are independent of the frequency of either grid, the question of grid discipline does not influence the trade. Payment is a matter for the respective SEBs, and we were not able to ascertain with any certainty whether payment schedules were met.

Institutional linkage

118. As stated above, there are no formal arrangements for trading between the RLDCs. However, RLDCs are operated under the aegis of Regional Electricity Boards, who are the responsibility of the Central Electricity Authority. The CEA is able to issue broad guidelines for the encouragement of trading between the RLDCs.

119. Lower level transfers through radial feeding can be agreed between adjacent SEBs. There is no requirement for adjacent SEBs in different regions to involve the respective REBs in any deal, although we understand they usually do.

120. Because the problems of intra-regional trade and grid discipline absorb the attention of the CEA and other interested parties, the question of inter-regional trade is relegated to a low order of priority. Developments in recent years have included some "teeth" for RLDCs, where a legal obligation to obey dispatch instructions is now included. This has not had much effect. RLDCs are gradually being taken over by PowerGrid, and their role strengthened in terms of dispatching central sector plant and controlling the EHV transmission system.

Costs and benefits

121. Because the AC radial feeds are so diverse and small, it has not been possible to calculate realistically debts arising from these trades. It is a little easier to assess the benefits of the DC link. This link operated at 46% load factor, and in doing so transferred nearly 2,000 GWh of thermal generation that would otherwise have been backed down into the Northern Region. We do not have all the details of this trade, but it is fair to assume from conversations with dispatchers in the Western Region and in the Northern Region that practically all the energy would have gone to reduce unsupplied energy in the Northern Region, rather than to reduce costs. We do not have an official figure for unsupplied energy in India, but, even using a modest figure, the benefits in reducing unsupplied energy are like to far outweigh the capital costs, even in a single year.

122. Transaction costs, i.e. the costs of actually conducting the trade appear to be quite low. The losses on the DC link are about 5%. There are no elaborate committee structures and legal costs in maintaining the trades.

123. The benefits of deepening and widening the Indian interconnections and the consequent volumes of trade depend in large measure on how successful India is in solving its undercapacity problem. There are clearly further substantial benefits to be had from reducing unsupplied energy if the generating capacity does not materialise. Unconstrained trading between the Northern, Western and Southern grids could increase savings by a further 3,000 million Rs.

Constraints

124. The purpose of this subsection is to identify the constraints on further trade between the Indian grids. These are dealt with under four subheadings.

Financial, economic and technical constraints

125. The use of the existing AC interconnections for the synchronous transfer and trading of power between the Indian grids is not possible. There is a widespread misconception that this impossibility is due to poor grid discipline. This is only partly true. The connections are relatively weak compared with the size of the grids, and it would need very expensive and very

sophisticated load and frequency control to be established within each regional grid if AC interconnection were to be maintained.

126. Trading on the AC links is therefore limited to those trades that can be accommodated by radial feeding. This implies relatively long term deals, and does not allow the quantity of electricity traded to be dictated by any other means than the load curve of the customers whose demand is transferred.

127. This means that all significant trades between the Indian Regions have to be carried out through DC transmission or back-to-back DC links. These are expensive compared with AC connections, and the availability of finance and the allocation of priority of financial resources to the construction of generating plant has been a constraint on the development of further inter-regional trade.

128. In the situation where each of the Indian grids is chronically short of capacity, trading is practically limited to the transfer of off-peak capacity to areas rich in hydro resources. There is also a little scope, occasionally, for economy trading, when backed-down energy in one region is cheaper than in its neighbour. It is doubtful whether the cost of DC links would be justified by the economy energy, but further significant savings can be made in unserved energy by trading off-peak thermal energy into hydro areas, and at any reasonable valuation of unserved energy this will justify expenditure on links. Recognising this fact, PowerGrid are proposing substantial DC links between the remaining regions where these have not yet been established.

Institutional constraints

129. We have not been made aware in this case study of any institutional constraints that would prevent economically justified inter-regional trade taking place over the existing link.

130. It could be argued that institutional pressures have delayed the installation of further DC links through competing pressures from PowerGrid and the central sector generators for share of central capital resources. NTPC argue that money is better spent on generating capacity, and PowerGrid argue that easing transmission constraints is more cost effective.

Contractual constraints

131. Trading between the regions is not covered by contract. Trading takes place between RLDCs which have a common ownership in CEA (and will eventually have common ownership in PowerGrid). There is no prima facie evidence that the existence of a contractual framework would improve the volume of trade which currently takes place through ad hoc arrangements between the regions.

Legal/regulatory constraints

132. The Regional Load Dispatch Centres organising the regional trade between grids all face a common regulatory and legal framework. The trade is not governed by contracts, and therefore is not in a strict sense legally enforceable. We were not able to identify any evidence to show there were problems in enforcing the ad hoc trading arrangements that are agreed from time to time.

Sector reform proposals

133. As PowerGrid takes over the responsibility for the Regional Load Dispatch Centres, it is actively looking at two principal sources of reform:

- A more rational monitoring dispatch control and clearance mechanism for the Regional Load Dispatch Centres, perhaps with some of the direct control of SEB plant being devolved to the RLDC.
- Implementation of a system of use of system charges for the transmission system, that is non-discriminatory and transparent.

134. Both of these reforms, when implemented, should improve the internal operation of the Regional grids. In doing so, it should create a more favourable environment to ensure inter-regional trade takes place on a sensible basis.

135. Private sector generation is being encouraged, but at present in the context of contracts between IPGs and individual SEBs. The concept of an open access electricity market in which generators compete to supply, and distributors compete to purchase, is not one that is being embraced at this time.

136. At state level, state governments are considering and, in some cases, working on the unbundling of generation, transmission and distribution within the states. This should help to encourage transparency of generation pricing and, again, act as an engine for improving intra-regional trade.

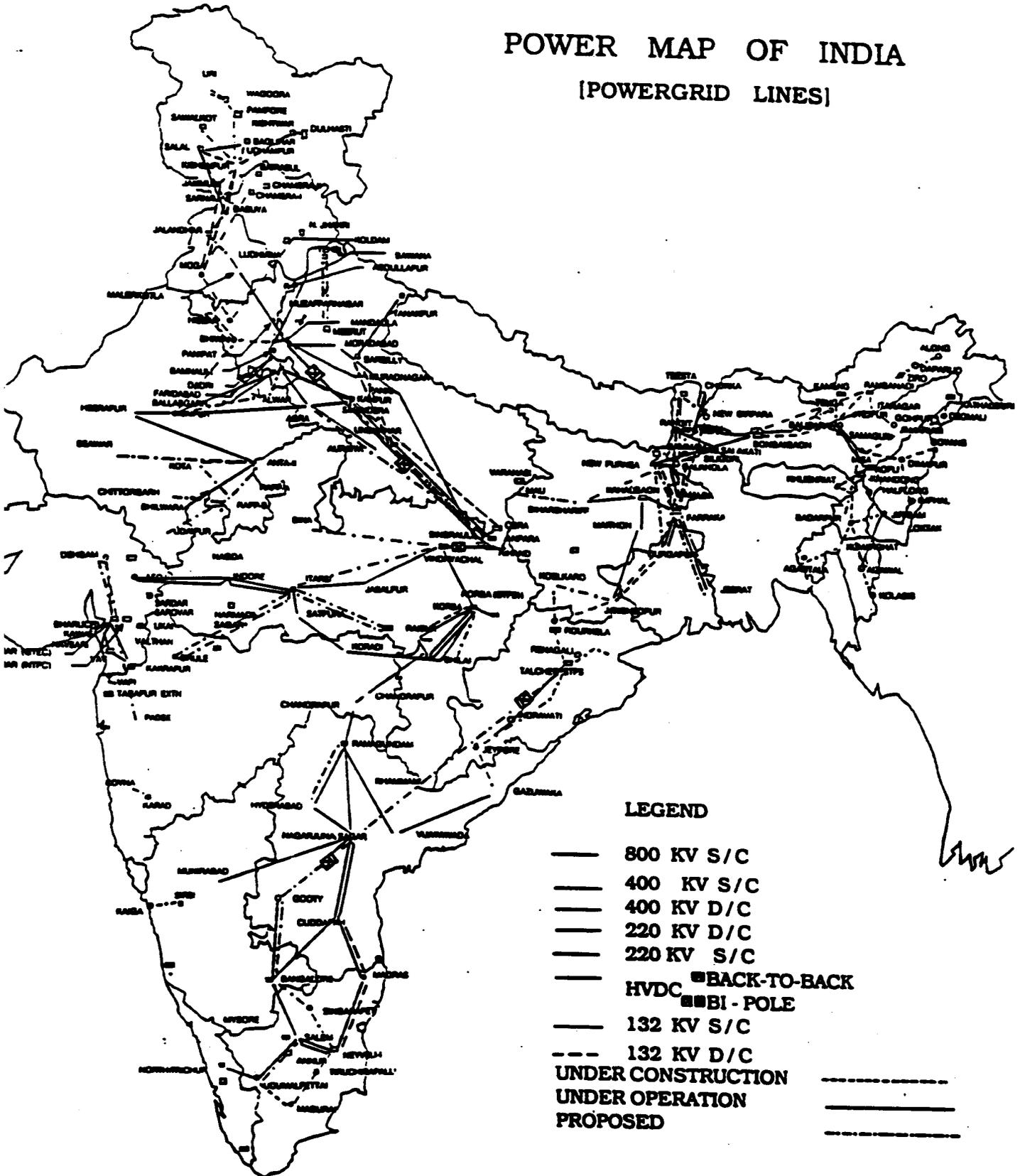
137. None of these developments seems likely to encourage the construction of generating plant in one region to supply another.

Environment

138. Because the Indian economy faces so many imperatives, and has so few degrees of freedom, environmental considerations are not material to inter-regional trade.

POWER MAP OF INDIA

[POWERGRID LINES]



LEGEND

- 800 KV S/C
- 400 KV S/C
- 400 KV D/C
- 220 KV D/C
- 220 KV S/C
- ■ BACK-TO-BACK
- ■ BI-POLE
- 132 KV S/C
- 132 KV D/C
- UNDER CONSTRUCTION
- UNDER OPERATION
- PROPOSED

NORDEL*

Introduction

1. The Nordel region covers the Nordic countries which are Denmark, Finland, Iceland, Sweden and Norway. As can be seen from Table 3.1, these countries are all fairly small in terms of population, but are characterized by high levels of both income, electricity output and electricity consumption (since the Icelandic power sector is not interconnected with the rest of Nordel, we do not include Iceland in any of the discussions below and, in particular, by the 'Nordel region' we will therefore mean the four countries Denmark, Finland, Norway and Sweden). The high levels of electricity output and consumption, especially in Norway, but also in Finland and Sweden, are explained by the availability of large amounts of cheap hydro power. This has been the basis for the establishment of relatively large energy-intensive industries and has led to high rates of domestic electricity consumption; in all countries electricity is the dominant energy source for heating as well as for other domestic purposes.

	Denmark	Finland	Norway	Sweden	All Four	EUR 12
Area, 1000 sq km	43.0	338.1	323.9	450.0	1,155.0	2,259.8
Population, mill.	5.1	5.0	4.2	8.5	22.8	328,649.0
GNP, billion ECU (PPP)	100.9	100.7	96.0	178.5	476.0	5,752.1
GNP per capita, '000 ECU (PPP)	19.8	20.1	22.9	21.0	20.9	17.5
Electricity production, TWh	23.9	52.9	120.5	138.5	335.8	1698.3
Electr. consumption per capita, MWh	6.3	12.6	24.7	17.0	14.7	5.3

2. As indicated by the figures in Table 3.1, the Nordic countries are very similar both in size as well as in living standards. The similarities between the countries, which include a common history and culture and similar languages¹, has provided an favourable environment for political

* This case study has been investigated by Nils-Henrik Mørch von der Fehr.

¹ The Scandinavian languages, Danish, Norwegian and Swedish, are very similar. Finnish, which is not among the Indo-European languages, is very different from the Scandinavian, but many Finns speak Swedish. Icelandic, although having common roots with the Scandinavian languages, is today very different from these, but most Icelanders speak Danish.

and economic cooperation. Cooperative efforts have been particularly strong in the decades following World War II, leading to the establishment of a Nordic Economic Zone which, with very few exceptions, gives complete freedom to trade and the movement of labour and capital between the countries.

3. Nordic cooperation in the electricity sector goes back to 1915 when the first interconnector between Denmark and Sweden was built. Interconnector capacities were gradually increased over the years, and, especially from the 1950s, international cooperation and power exchange became important for the performance of the various national electricity supply industries. With increasing integration of the national industries there was a need for closer coordination between them. Nordel was founded in 1963 with the objectives of providing a forum for discussion among members of the national electricity industries and to make recommendations for the improvement of the efficiency of the entire Nordic electricity supply industry. Membership of Nordel was limited to 'prominent members of the national electricity supply industries'. There are currently five members from each country, chosen so that both generator and transmission/distribution companies are represented. The presidency is rotated among the countries every third year. In addition to the main council, a number of working committees have been established covering issues such as investment planning, system cooperation and statistics and information. Most of the actual work of the organization is undertaken by these committees, as well as by various ad-hoc committees set up to consider particular issues.

4. As stated in Nordel's by-laws, its tasks include:

- technical coordination of the Nordic power generation and transmission systems;
- the establishment of a technical framework for Nordic electricity industry cooperation;
- international co-operation with other regions, in particular with the rest of Europe;
- to establish and develop contacts with other parties, organizations and governments operating within the electricity sector; and
- spread information about Nordel.

5. Nordel has no formal powers and its members do not represent the governments of their respective countries. The organisation is basically an 'industry club', with the aim of influencing the development of the Nordic electricity supply industry. Since its members represent the most important players in the various national industries, Nordel has been very influential and its

recommendations are generally followed. Nordel has worked closely with the Nordic Council which is the main forum for economic and political cooperation between the Nordic countries.

6. The Nordic pool is extremely 'loose', and, with the exception of a few long-term contractual arrangements for exchange of power, day-to-day exchange, frequency stabilization, as well as co-operation on other aspects of the system, are based on bilateral, informal 'gentlemen's' agreements'. That such an informal system can work with a considerable degree of success is partly explained by the tradition of cooperation among the Nordic countries. However, cooperation has also worked because it has been limited to areas in which all participants' interests have been more or less perfectly aligned, such as technical coordination and system stability control, and where coordination did not infringe upon the individual countries' policies of national system control and self-sufficiency in energy production. Also, given the agreement within Nordel to base short-run exchange on the 'split-savings', or 'mid-price', principle, day-to-day economy exchange has worked quite well. Cooperation has been much more difficult to achieve in areas which could be deemed in conflict with national control and self-sufficiency, or where gains would be more one-sided, and which would therefore have to involve commercial arrangements with monetary compensation. For example, third-party access to networks has generally been denied and there are few examples of energy trade on (long-term) contracts. The fact that profitability was never a very important motive in the industry (i.e. before deregulation), probably also help to explain why commercial arrangements have been difficult to establish.

7. With the recent deregulation of the electricity industry in Norway, which will be followed by similar developments in Finland and Sweden, the immediate consequence has been that the cooperative 'climate' has become somewhat more difficult. Nordel, as a forum for the electricity supply industries, initially voiced its members scepticism towards the introduction of market-based trade, arguing that, by turning what used to be partners into competitors, cooperation would become more difficult and no one would care for the quality of the overall system. However, as first the Norwegians, and gradually also the Finns and the Swedes, have come to accept, and even favour, the changes that are taking place, there has been a strong debate within the Nordel organization itself. Gradually events have been accepted and Nordel has adjusted its tasks and the organization accordingly. One would expect that, once the new policies have been implemented in Finland and Sweden (Denmark does not have any plans at the moment to deregulate its industry), Nordic cooperation in the electricity sector will continue with the same success as in previous years. Indeed, with market-based trade in electricity and more focus on economic efficiency (and, consequently, less reliance on self-sufficiency in energy), cooperation can be extended even further to include also long-term trade in power.

The power systems and interconnectors

In 1992, the total installed generation capacity in the four countries Denmark, Finland, Norway and Sweden was 84,824 MW (Table 3.2), while annual production reached 341,179 GWh (Table 3.3). Of total installed capacity, 55% was hydro, 31% thermal and 14% nuclear. The total installed interconnector capacity within Nordel is 12,810 MW, or approximately 18% of total generation capacity. In 1992, internal exchange reached 23,175 GWh, or 7% of annual production. Whereas, on average, interconnectors have modest load factors, capacities can be fully utilized in periods (e.g. during winter days when Denmark meets peak loads by importing power from Norway, or in summer when Norway exports its hydro surplus to neighbouring countries). There are considerable differences between the countries, both with respect to installed capacity of different technologies, the organisation of the industries and interconnector capacities. However, in all countries the development of the electric power sectors are mainly the result of negotiations, cooperation and coordination among the major agents, and with only weak formal, government regulations. In each country, there exists a mix of small and large, private and public utilities, but the development of industries have to a large extent been characterized by publicly-owned, dominant-firm leadership based on self-enforced 'gentlemanly cooperation'. Below we briefly describe the electricity supply industry in each of the four countries and provide details on the interconnector capacity with other Nordel countries as well as with countries outside of the Nordel region.

	Denmark	Finland	Norway	Sweden	Total
Total	9,506	13,546	27,236	34,536	84,824
Hydro	10	2,748	26,958	16,380	46,096
Nuclear	0	2,310	0	10,000	12,310
Thermal	9,496	8,488	278	8,156	26,418

Table 3.3: Production, 1992 (GWh)					
Source: Nordel annual report 1992.					
	Denmark	Finland	Norway	Sweden	Total
Total	28,770	54,690	117,681	141,038	341,179
Hydro	26	14,986	117,259	72,664	204,935
Wind	793	1	0	33	827
Nuclear	0	18,195	0	60,841	79,036
Thermal	27,951	21,508	422	7,500	57,381

Denmark

9. Denmark has the smallest electricity sector among the Nordic countries and is also the only country which is more or less completely based on thermal power (Table 2). 94% of the fossil fuels are coal, the rest being mostly oil and some gas. Approximately a third of the electricity output is consumed by the manufacturing industry, a third by other businesses and the last third by domestic users. Denmark is unique among the Nordic countries for having a large-scale program (initiated by the Danish Government) to increase the use of alternative, environment-friendly energy sources, and wind-turbine electricity production now has a share in total generation of 2-3%.

Not only the plant and technology mix but also the ownership and market structure of the Danish electricity supply industry is different from that of the other Nordel countries (Table 3.4). In Denmark, the state is not directly involved in the electricity supply industry. Whereas in the other Nordic countries, the state was instrumental in securing supplies of cheap hydro power to energy intensive industries, and thus became important in the development of the electricity industry, in Denmark, lacking both heavy industry and hydro resources, municipalities took the lead in the electrification of the country. The Danish electricity supply industry consists of two completely separate grids; the western Elsam grid which covers Juteland and the island Fyn, and the eastern Elkraft grid covering Sjælland and surrounding islands. In 1992, slightly less than 6% of the total generation capacity was privately owned, the rest being municipal. However, in both regions there is close cooperation between the various utilities, and thus the Danish industry is best described as consisting of two separate, vertically integrated systems. In particular, Elsam and Elkraft, which own the transmission grids in their respective regions, are responsible for the operation of both generation and transmission. There are currently no plans to deregulate the Danish electricity supply industry, and, if anything, the current policy is to further integrate the systems, both horizontally and vertically.

10. Situated to the south in the Nordel region, Denmark is interconnected to the north with the Nordel countries Norway and Sweden and to the south with Germany. Only the Elkraft grid is interconnected by AC cables to the rest of the Nordel, while the Elsam grid, although being linked by DC cables to Norway and Sweden, is interconnected by AC cables to the UCPTE grid. To the north, Elsam is connected to Norway by two DC cables of a total capacity of 990 MW, and to Sweden by two DC cables of total capacity 560 MW. To the south, the Elsam grid is connected to Germany and PreussenElectra by two AC 400kV and two AC 220kV cables with a total interconnector capacity of 1400 MW. The Elkraft region is connected to Sweden by two AC 400kV cables and one AC 132kV cable of total capacity 1050 MW in the direction of Denmark and 1450 MW from Denmark. A DC cable from Elkraft to Germany is under construction and will be finished by 1995. The Elkraft and Elsam regions will be interconnected by 1997 (planned interconnector capacity: 500-600 MW). All interconnectors are owned and operated by either Elsam or Elkraft.

Table 3.4: Ownership structure, 1990 (percentage of generation/customers)
Source: Hjalmarsson 1993.

	Denmark		Finland		Norway		Sweden	
	Gene-ration	Distri-bution	Gene-ration	Distri-bution	Gene-ration	Distri-bution	Gene-ration	Distri-bution
State	0	0	46	0	25	0	55	11
Municipalities/ Counties/Co-ops	98	100	18	75	38	80-90	20	64
Private	2	0	36	25	38	10-20	25	23

Finland

12. Of the total Finnish generation capacity in 1992 of 13,546 MW, 63% was conventional thermal, 20% hydro and 17% nuclear. Finland is generally dependent on imports of power, both from the other Nordel countries as well as from outside (Russia), and in 1992 imports accounted for 14% of total electricity consumption. In that year, total energy consumption was 62.9 TWh, 53.9% of which was consumed by the manufacturing industry. Finland has the highest private-generator market share among the Nordel countries. However, the industry is dominated by the publicly-owned Imatran Voima Oy (IVO) which is responsible for 40% of generation.

13. In the southern part of the country, a private company, TVS, owned by private manufacturing industry, operates parallel transmission links to the main grid (investment and operation of the grids are, however, closely coordinated between IVO and TVS). IVO and TVS are involved in direct power exchange, while all other, smaller generators exchange power with either IVO or TVS. Short-run coordination of despatch is governed by a 'club contract', containing rules for eg, frequency and voltage regulation, despatch (merit order despatch is based on bilateral power exchange priced by the 'split-savings' principle) and maintenance of plants. There are 130 distribution companies, most of which are owned by municipalities. The 35 largest distribution utilities supply approximately 75% of the consumers.

14. From 1994, a new electricity legislation has been introduced, one part governing competitive conditions and the other security aspects. The aim of the new legislation is to gradually move the electricity supply industry towards a more market-based organisation. As part of the new policy, in 1992 the public grid, previously owned by IVO, was divested from the mother company to be operated by a new grid company IVO Voimansiirto Oy (IVS). For the time being, IVO will continue to be responsible for the operation of the international interconnectors.

15. Finland marks the eastern border of the Nordel region and to the west, it is interconnected by AC cables to Norway and by both AC and DC cables to Sweden. To the east, Finland is interconnected by AC cables to Russia. The Finland-Sweden AC capacity, consisting of two 400kV cables and one 220kV cables, is 900 MW in the direction of Finland and 700 MW in the direction of Sweden. In addition there is a 400kV DC cable of 500 MW between the two countries. Finland and Norway is connected by an AC 220kV cable with a total capacity of 50 MW. The Russian interconnector capacity consists of two AC 110 kV cables with a total capacity of 150 MW in the direction of Finland (0 in the other direction) and one DC 85kV cable with a capacity of 1065 MW. There are currently no plans to extend the interconnector capacity between Finland and other countries.

Norway

16. Norway has an almost completely hydro based electricity industry. Of the total installed generation capacity of 27,236 MW, more than 99% is hydro. Annual production varies considerably, depending both on water inflow and demand (which again depends on temperature). In 1992, total production was 117.7 TWh, which is approximately 9% higher than mean production capacity, estimated to equal 108 TWh. Norway is the only Nordel country which is on average a net exporter of electricity, and in 1992, net exports accounted for 7% of total output. The manufacturing industry accounts for slightly less than half of inland consumption (45.1% in 1992). The total reservoir capacity of the Norwegian system is 79.3 TWh (mid-1992) which equals 73% of mean annual production.

17. The total generation capacity is divided among more than 100 producers, where the largest is the state-owned Statkraft SF, which owns 30% of total capacity, and the rest are small and medium-sized, private and municipal companies. So far, the Norwegian electricity supply industry is unique among the Nordel industries for being more or less completely deregulated and market based. With the new Energy Act, which took effect 1 January 1991, the central grid was divested from Statkraft and is now owned and operated by and independent, state-owned grid company, Statnett SF. Statnett has taken over responsibility for the Pool also, which previously was operated as a producers' association. Power is traded on long-term contracts outside of the Pool, as well as in the three Pool markets; a spot-market and two futures markets, one for week-ahead sales and another for year-ahead sales. The markets are open for all, including generators, distributors, suppliers, traders and consumers. In May 1992, a new set of transmission tariffs came into effect, replacing an old tariff structure more similar to that of the other Nordel countries and with fees related to amounts of energy transported and the distance between buyer and seller. The new tariff structure includes fixed, capacity-based charges in addition to a two-part energy-based fee related to transmission losses and constraints ('bottlenecks'); one part (the 'Energy Fee') equals a (time and node dependent) marginal loss factor times the actual spot price of electricity; the other part (the 'Capacity Fee') is calculated as the difference between an overall market-clearing price, not taking constraints into account, and prices calculated separately for each side of the bottleneck (a high price in the deficit area, and a low price in the surplus area, so that the transmission capacity is just fully utilized). The new tariff structure, by removing the distance-related element in the old tariffs, and thereby an artificial barrier to trade, has greatly improved the prospects for competition in the long-term contracts market.

18. Norway, which marks the northern and western borders of the Nordel region, are interconnected to the south with Denmark, to the east with Sweden and Finland, and to the north with Russia. The main interconnector capacity to and from Norway are the 9 AC cables to Sweden (three 400kV, one 275kV, two 220kV and three 132kV cables), with a total capacity of 2250 MW in the direction of Norway and 2070 MW in the direction of Sweden. Norway is interconnected with Denmark by one DC 250kV cable and one DC 350kV cable, with a combined capacity of 880 MW. The two cables connecting Denmark and Norway are operated under long-term contracts between Elsam and Statkraft, the Norwegian state-owned generator. In addition to the Nordel interconnectors, Norway is also inter-linked with Russia by an AC 154kV, 50 MW cable. There are currently plans build sub-sea cables to interconnect directly with Germany and the Netherlands (thereby evading the Danish grid, see below), as well as with Britain. The Norwegian Government has recently given concession for the building of a 600 MW cable to Germany which will come into operation in 2003.

19. Statnett owns and operates the international interconnectors, and is responsible for day-to-day power exchange with the rest of Nordel (see below on the organization of short-run exchange between Norway and its neighbouring countries). Power is also traded with Denmark, Germany and Sweden under long-term contracts between (groups of) Norwegian producers and foreign partners. To avoid an increase in domestic electricity prices, the total volume of exports on long-term contracts have been limited by the Norwegian Government to 5 TWh per year.

Sweden

20. The Swedish electricity industry is the largest of the Nordic industries, with a total installed generation capacity of 34,536 MW. Of this, 47% is hydro, 29% is nuclear and 24% thermal. In 1992, 39.5% of the total domestic consumption of 138.8 TWh was consumed by the manufacturing industry. The Swedish power industry is dominated by the publicly owned Vattenfall which generates about 50% of total output. The ten largest distributors together account for 90% of generation while 300 distributors are responsible for distribution and supply. Although vertical integration is common, most retailers are also net buyers of electricity. Generation and transmission has been ruled by a club of the 10-15 largest utilities, although, formally, Vattenfall was the sole owner of the main grid. To facilitate efficient use of existing capacity, the 6 major producers operate a short-run power exchange based on bilateral, 'split-savings' contracts. Vattenfall is responsible for operations management, including the monitoring of load distribution, voltage regulation and relay settings. Transmission is based on long-term wheeling contracts with capacity/distance related payments: Members of the grid club subscribe to 'channels', ie, the right to transport a certain amount of power over a specific distance, and pay a fee per MW km. The marginal

cost for a contract holder of using his channels is zero. Utilization of excess capacity in the grid is determined at the discretion of the grid owner, Vattenfall.

21. Following deregulation in Norway, the Swedish industry is currently undergoing a transformation towards a more market-oriented structure and organisation. In 1992, Vattenfall was transformed into a limited-liability company, with plans to privatize the company some time in the future. Separation between transformation and generation has been introduced with the creation of a new, publicly-owned company, Svenska Kraftnät, responsible for operating the high-voltage transmission grid, including the international interconnectors. A new legislation will take effect from 1995, with the aim of further promoting market-based trade in electricity and the creation of a power pool.

22. Sweden is situated in the middle of the Nordel region, with Denmark to the south, Finland to the east and Norway to the west, and is the only Nordel country to be interconnected with all the others. The Danish-Swedish interconnector capacity consists of 3 AC cables (two 400kV cables and one 132kV cable) to eastern Denmark (Elkraft) with a total capacity of 1050 MW from Sweden and 1450 MW to Sweden, and two DC cables of 250kV and 285kV, respectively, to western Denmark (Elsam), with a total capacity of 560 MW. The Norwegian-Swedish interconnector capacity consists of 9 AC cables (three 400kV cables, one 285kV cable, two 220kV cables and three 132kV cables) with a total capacity of 2250 MW from Sweden and 2070 MW to Sweden. Sweden is connected to Finland by 2 AC 400kV cables and one AC 220kV cable, with a combined capacity of 900 MW in the direction of Finland and 700 MW in the direction of Sweden, and one DC 400kV cable with a capacity of 500 MW. From 1994, Sweden will be interconnected with Preussen Elektra in Germany by a DC 400kV cable with 600 MW capacity.

Interconnection arrangements

23. The total installed interconnector capacity is summarized in Table 3.5. Interconnector capacity within the Nordel region equals 18.2% of total installed generator capacity. There are considerable differences between the countries, partly explained by geographic location and partly by the technological characteristics of the power systems, with Denmark having the highest relative rate of interconnector capacity and Norway the lowest. As can be seen from Table 3.6., imports and exports vary considerably between the countries. Trade also varies between seasons and between years, depending on the inflow of water in the hydro systems in Finland, Norway and Sweden. All four countries have had policies of self-sufficiency in electricity up till now, and even though there has been an increasing trend in exchange volumes, as a fraction of domestic consumption exchange has not increased. In the last years, Denmark and Finland have generally been net importers, Norway has been a net exporter while Sweden has had a net balance close to zero.

Table 3.5: Interconnector capacities, 1993 (MW)
Source: Nordel annual report 1992

To:	Denmark	Finland	Norway	Sweden	Nordel	Other	Total
From:							
Denmark	-	0	990	2,070	3,060	1,400	4,460
Finland	0	-	50	1,235	1,285	1,065	2,350
Norway	990	50	-	2,070	3,110	50	3,160
Sweden	1,670	1,435	2,250	-	5,355	0	5,355
Nordel	2,660	1,485	3,290	5,375	12,810	2,515	15,325
Other countries	1,400	1,215	50	0	2,665		
Total	4,060	2,700	3,340	5,375	15,475		
Interconnector capacity in percent of generator capacity	42.7%	29.9%	12.3%	15.6%	18.2%		

Table 3.6: Exports and Imports, 1992 (GWh)
Source: Nordel annual report 1992

Import to:	Denmark	Finland	Norway	Sweden	Nordel	Other	Total Export
Export from:							
Denmark	-	0	57	1,474	1,531	3,353	4,884
Finland	0	-	5	691	696	0	696
Norway	3,159	105	-	6,681	9,945	0	9,945
Sweden	5,374	4,453	1,176	-	11,003	0	11,003
Nordel	8,533	4,558	1,238	8,846	23,175	3,353	26,528
Other countries	118	4,384	32	0	4,534		
Total Import	8,651	8,942	1,270	8,846	27,705		
Net Import	3,767	8,246	-8,675	-2,157	1,181		
Net Import in percent of total consumption	11.6%	13.1%	8.7%	1.7%	0.4%		

24. **Short-term exchange:** With the exception of the arrangements covering the interconnectors between Denmark and Norway, and a few long-term contracts between Norwegian generators and Swedish buyers, all power transmitted between the Nordel countries is exchanged on a day-to-day basis. The arrangements covering the short-run exchange are bilateral and informal between the companies responsible for despatch in each of the countries. Prices are generally determined by a 'split-savings' pricing rule, which involves each operator informing the trading partner of its system marginal costs and the price being set as the average of the costs of the two systems (prices are capped, such that in emergency situations buyers are protected from having to pay excessive prices). Clearly, such a rule requires openness and trust (rumours say that manipulation of marginal cost declarations has happened, but the general impression is that such events have been rare). With the deregulation of the Norwegian industry, Sweden, Norway's main trading partner, has refused to base payments on a mid-price formula calculated on the basis of the market prices in Norway. The argument has been that bids in the Norwegian pool are distorted above costs, and thus a mid-price between an inflated Norwegian market price and Swedish system marginal costs would favour the Norwegians. This has resulted in a complete change in the way short-run exchange is organized between Norway and its trading partners; now Swedish (as well as Danish) buyers and sellers bid into the Norwegian pool and power exchange is regulated according to sales/purchases as determined by the pool merit order. Bids can be submitted both in the spot market and in the forward market for purchases/sales up till 6 months in advance. Following the change in the organization of trade, short-run exchange between Norway and Sweden has been lower in 1992 and 1993 than in previous years, but is expected to increase as participation in the market is extended further. In accordance with the pre-deregulation tradition, Swedish generators have tended to coordinate their bids through their main generator, Vattenfall, but gradually the various participants have begun submitting bids on an individual basis.

25. **Long-term contracts:** Of the modest volumes that are exchanged under long-term contracts, those between Denmark and Norway are the most important. The first of the interconnectors between these countries was built in 1977 under a 'buy-back' contract which allowed Elsam to take deliveries of up to 270 MW during 6 hours of the peak-load time during the day and return the energy at night (the returned energy shall equal 115% of day-time take). Trade was supposed to balance, although Statkraft was given the right to decide how much energy should be traded on a net basis (Statkraft can also disrupt deliveries up till 10 days a year). In the case of discrepancies, these would be priced at 'avoidable cost', i.e. marginal system cost in the Elsam region; for deliveries from Denmark the price is set equal to 110% of the increase in fuel costs and for deliveries from Norway to 70% of fuel cost savings. Over the years it turned out that Norway had a larger excess supply than originally forecasted, and thus Norway has tended to be a net exporter over the interconnector. In recent years, two new interconnectors have been built, parallel to the old, and the associated contract includes a clause for firm-power deliveries of 1 TWh per year from Norway.

26. With the liberalization of international trade to and from Norway, there has been a considerable increase in interest among Norwegian generators for exporting power. Exports (and imports) on short-term contracts of up to 6 months duration, through the forward market in the Norwegian Pool, is in principle completely liberalized. In the autumn of 1992, the upper limit for power export not subject to concession was stipulated at 5 TWh under contracts of up to 5 years' in duration. This limit has now been reached by contracts between (groups of) Norwegian generators and Swedish buyers.

27. In addition to the 5 year contracts, the Norwegian Government can grant concession for the sale of effect and energy under contracts of more than 5 years' duration. In the summer of 1993, Statkraft obtained concession for a long-term contract with the German PreussenElektra. This contract is similar in structure to the Danish-Norwegian contracts and involves power exchange on an 'energy neutral' basis, but with certain options for net energy trade. Indeed, the Norwegian Government, as part of the concession, has required Statkraft to import in periods when the Norwegian spot price exceeds marginal system costs in Germany (net of transport costs) and vice versa. The contract limits exchanges to 400 MW, which will be wheeled over the Danish grid (the details of the commercial arrangements are not public), plus 600 MW over a new sub-sea interconnector which will come into operation in 2003. The new interconnector will be built and operated by a new company, Viking Cable, owned 50/50 by PreussenElektra and Statnett.

28. In June 1993, EuroKraft Norge, a group of 22 Norwegian producers, signed an agreement with the German Hamburgische Electricitäts-Werke AG for building another 600 MW sea cable between Norway and Germany. The interconnector would come into operation in 1998, and again power exchange would be on an 'energy neutral' basis. The Norwegian Ministry of Energy and Industry refused to grant a license, arguing that the agreement was not 'economically sound' from a Norwegian point of view. It would seem that the Ministry's main concern was that the contract did not secure a sufficient degree of supply security, by allowing net imports to Norway in periods of insufficient domestic supply. Statkraft has recently applied for a concession to trade power with the Netherlands. The arrangement will involve the building of a new interconnector by Statnett in cooperation with the Dutch Samewerkende elektristeitsproductiebedrijven (SEP). Discussions are currently taking place also between Norwegian generators and prospective buyers in the United Kingdom to explore the opportunities for building interconnectors between the two countries.

29. **Interconnector pricing:** Since, as a rule, external exchange has been the responsibility of the dominant national utility, which was also owner and operator of the high-voltage transmission grid, the decision to invest in interconnector capacity came to be based on bilateral agreements between the respective national players (Elsam/Elkraft, IVO, Statkraft and Vattenfall/Sydkraft). The sharing of investment costs, as well as operations costs (including

those associated with transmission losses), was determined by the contract and has varied between projects depending on their particular character.

30. Only in those cases in which building and use of interconnectors were not done by one and the same utility did pricing of interconnector services become an issue. Historically there were only few examples of this (eg. in addition to Vattenfall, some Swedish utilities owned interconnectors to Norway), but with the current separation between generation of transmission taking place in Finland, Norway and Sweden, this issue has become more important. The principles for pricing use of interconnector capacities vary between the countries, reflecting the differences in transmission tariff structures: For example, in Norway, all export and import of energy is subject to an energy fee reflecting the marginal transmission loss at the border-node and equalling a (marginal) loss factor times the actual spot price of energy. In addition, exchange under long-term contracts are subject to a capacity fee and a priority fee (which entitles the holder to export/import a certain amount of power). Unused interconnector capacity (including that which is paid for, but not utilized), may be used by Statnett for short-term exchange via the spot market. On the other hand, in Sweden, the buyer/seller will have to contract for a 'channel' from the Swedish side of the border all the way to his own location, and his transmission tariffs will depend on the length and capacity of this 'channel'. Interconnector capacity not under contract, or contract 'channels' not used, may be sold on a day-to-day basis by the grid owner to interested importers/exporters.

31. Clearly, interconnector pricing arrangements can act as important barriers to trade. For example, if the newly established Swedish grid operator, Svenska Stamnät, were to introduce nodal pricing based on the same principles as in Norway, trade between Norway and Sweden would involve an energy fee, not only at the respective nodes of the Norwegian party and the Swedish party, but also at the two nodes on each side of the border. While the former fees are well justified on efficiency grounds, the latter are not, and from an integrated regional network point of view should be set equal to zero in order not to interfere with trade. Statnett has started talks with Svenska Stamnät with the aim of coordinating transmission tariffs so as to avoid that they act as trade barriers.

32. **Institutional and legal framework:** The underlying principles for trade and interconnector operation have generally been discussed collectively among the Nordel members and actual arrangements have tended to follow the recommendations of Nordel. However, since formal agreements have been few, and because Nordel has no formal powers, the organization can do very little to enforce adherence to the agreed rules. In particular, besides providing a forum for arbitration and resolution of conflicts, Nordel has no possibility to impose any sanctions. Now, in practice, such conflicts have been very rare, if they have happened at all, and so the robustness of the system (or lack of such) has not been put to any severe test. In those cases where formal, written agreements have been made, contracts have been bilateral. Trade under such bilateral contracts has been no different from any other export/import agreement and

the particular procedures for arbitration in cases of disputes are a matter for the contracting parties to agree upon. Again, there appears to have been no disputes associated with these contracts which could not be resolved between the parties themselves.

Costs and benefits of interconnection

33. Nordic cooperation in the electricity supply industry has concentrated mainly on the coordination of technical standards and investment in interconnector capacities to increase the overall reliability and security of supply and to save on reserve capacity. It would seem that, at least from a technical point of view, much of the potential benefits from such measures has now been realised. Although some efforts have been made, there seems to be additional gains from further integration of the hydro system in Norway with the more thermal-based systems in other countries, including Continental Europe. These gains will come partly from better utilization of seasonal variations in water availability and opportunities for water storage in reservoirs, and partly from the Norwegian comparative advantage in energy production (cheap hydro).

34. Nordel policies have been concerned mostly with aspects that affect system reliability and security, i.e. what is often referred to as 'quality of supply'. Over the years its recommendations have involved matters such as the sharing of information on investment plans, technical compatibility, frequency and voltage deviation standards, coordination of power plant maintenance and despatch in emergency situations, reserve margins, transmission network capacities and voltage levels and interconnector capacities. The main benefits of these measures seem to have been increased efficiency in each of the national systems from the sharing of information and technical know-how and from achieving scale economics and savings on reserve margins by reducing the need for building thermal plant to meet peak-load demand. Nordel has also encouraged short-run power exchange to realize economy-energy savings from better utilization of existing production capacity. While these measures have increased efficiency, in particular, by higher capacity utilization, capabilities to meet (average) energy demand have not been affected. As a consequence of the policies of self-sufficiency, gains from comparative advantages in energy production (i.e. substitution of cheap Norwegian hydro for expensive thermal capacity in the other countries) has not been realized to any large extent.

35. There are both short-run and long-run gains from integrating a hydro system with a thermal system. One short-run gain is that interconnection allows the use of hydro capacity for 'energy interchange' by meeting peak-load demand in the thermal system with energy deliveries from the hydro system, which are then subsequently returned in off-peak periods. Interconnection of hydro and thermal systems also leads to more efficient use of water by allowing deliveries of energy to the thermal system produced from water that would otherwise have been spilt, something which occurs mainly during spring and summer. Interconnection with a thermal system leads to greater supply security in the hydro system since imports can be used to compensate for low production in dry years. In addition to short-run savings on fuel and

water, interconnection leads to long-run savings on peak-load capacity in both systems as well as savings on reservoir capacities. Such potential gains were the basis for the first interconnector built between Denmark and Norway, as well as for the new interconnectors between Norway and Denmark and Norway and Germany.

36. It is difficult to estimate precisely the overall gains of interconnection in the Nordel region and, as far as we know, such estimates are not available. However, estimates of some specific measures have been calculated and seem to indicate that the overall gains are substantial: In a book published in 1988 to celebrate the first 25 years of Nordel, the gains just from economy-energy savings are indicated to have been 'billions of Swedish kroner' over this 25 year period. According to an article in 'Elsam-posten', the gross gains from the first interconnector between Denmark and Norway, which was built in 1977 at a cost of 750 million DKR, have been 2 billion DKR to Norway and 1 billion DKR to Denmark over the first 14 years of operation. Nordel also publishes estimates on 'environmental savings'; in 1992, and compared with a situation in which each country produced so as to be self-sufficient in energy, electricity exchange reduced emissions of pollutants by 29,000 tons SO₂, 32,000 tons NO_x, 16 million tons CO₂ and 380,000 tons of ashes.

37. Even though the overall benefits are substantial, there are indications that further gains are possible, in particular if trade in energy is increased. An indication that not all potential gains have been realized is given in Table 3.7. which shows estimates of average prices on firm-power deliveries to the manufacturing industry in each of the Nordel countries. Clearly, these variations are greater than what can be explained by transmission losses and other technical or economic constraints that would limit the benefits from trade. Attempts to quantify the effects of liberalization of trade between the Nordic countries, as well as with countries outside of the Nordel region, show that a number of existing interconnectors, in particular those between Norway/Sweden and (via Denmark) Continental Europe, would act as constraints, indicating a potential for further expansion of interconnector capacities (Bjørndalen, 1990; Amundsen et.al, 1993). Interestingly, these calculations show that much of the potential for trade between the Nordic countries is already exhausted (given the existing structure of generation capacities), and that the largest gains will result from further integration of the Nordel region with the rest of Europe. A further indication that this view may be correct is the recent agreement to build an interconnector between Germany and Norway.

Table 3.7: Average Prices, firm-power deliveries to industry, 1989 (NOK/kWh) Source: Bjorvatn, 1990.			
Denmark	Finland	Norway	Sweden
0.42	0.35	0.11	0.24

Issues

38. Neither financial, economic, contractual, legal, regulatory or technical constraints have been important in determining the direction and pace of development of cooperation within the Nordel region. Indeed, the constraints so far, as well as on further integration and cooperation, seem to be primarily institutional. Self-sufficiency in electricity has been an important goal for all the governments involved. Furthermore, politically determined long-term supply contracts with the energy-intensive industries has reduced the amount of energy available for export from Norway. In the last years, special problems have been created by the various countries having different policies towards deregulation of the electricity supply industry. As a result, the framework for power exchange between the countries has had to be reorganized.

39. All of the Nordel countries have been committed to policies of self-sufficiency in electricity (for some countries this commitment includes all energy sources, and Denmark is currently following a policy of less reliance on imported fuels by encouraging the use of domestic gas supplies). These policies have reduced export and import volumes of energy below levels that would have resulted from free trade. Day-to-day power exchange has not been limited by any formal constraints, and as a consequence, exchange volumes have been quite considerable and increasing over the years. However, while this trade has involved gains from economy energy and load and fuel diversity, to the be able to reap the benefits from comparative advantages in energy production, national energy-capability-investment policies must be changed. Within the industries, the traditional argument has been that for imports to replace domestic energy capacity, supply-security concerns require that trade contracts are for firm power and very long term. The merit of this argument is not obvious, but, since eg. Norway, the main potential exporter, has discouraged exports on long-term contracts, it probably goes some way towards explaining the policies in Denmark and Sweden of building generation capacities to keep abreast of demand, and thus limiting the potential for trade. Interestingly, following deregulation in Norway and falling prices in both spot and contracts markets, the Norwegian electricity supply industry has become an important lobby for freer trade. The Norwegian government, having limited exports on long-term contracts to 5 TWh per year in order to avoid an increase in domestic prices, seems gradually to accept the arguments for freer trade and one would expect to see an increasing volume of exports from Norway in coming years.

40. The argument for securing supply by complete control over the national electricity industry is also important for understanding the difficulties in reaching agreements that involve the use of other countries infrastructure, i.e. third-party access to national grids. For example, until now, Norway and Sweden have only been able to trade with Continental Europe via the Danish grid. The Danes have insisted on organizing this trade on a bilateral basis, i.e. by buying power from Norway and Sweden and reselling it to Germany. The building of interconnectors between Sweden and Germany, and between Norway and Germany, is partly a result of a strategic game whereby the Norwegians and Swedes, by establishing direct links to Continental Europe and thus evading the Danish grid, strengthen their bargaining position towards the Danes. (It must be noted, however, that the capacity of the Danish grid is limited and that the building of new cables in Denmark are generally met with heavy opposition from environmental pressure groups. Thus for trade between the Northern parts of the Nordel region and Continental Europe to increase much further, some new, direct, sub-sea links will probably have to be built anyway). Denmark have traditionally argued the need for complete control over all power transmitted over its grid, but seems to have been easing this policy recently. The agreement covering the use of the new interconnector between Denmark and Norway includes a clause on third-party access to the Danish grid, thereby allowing direct trade between Germany and Norway.

41. The change of policy in Norway lead to much debate within Nordel and a 'souring' of the 'cooperative climate'. Some expressed the concern that Norway, by introducing a completely new organisation of electricity trade, and thus leaving the principles advocated by Nordel, was undermining the basis for cooperation within the region. The immediate consequence was that Sweden refused to base short-run power exchange on the mid-pricing principle, arguing that the spot-price in the Norwegian market was biased above the underlying system marginal cost. Consequently one had to develop a new system for pricing power exchange, and, as explained above, this now occurs by Danish and Swedish utilities bidding into the Norwegian Pool. Following the new organization of trade, power exchange between Norway and Sweden seems to have been reduced somewhat compared to earlier years. This is most reasonably explained by transitional problems in adapting to the new trading regime. More speculatively, an additional reason may be that Vattenfall, which, by its considerable size, has some market power in the Norwegian Pool, has attempted to manipulate prices by reducing trade volumes.

Key lessons

42. By its own standards, Nordel considers Nordic cooperation in the electricity supply industry to have been a success. Thus, one way of viewing the Nordel experience is that even within institutional constraints of national self-sufficiency and control, and an organisational setup involving a very 'loose' pool, considerable efficiency gains can be made from interconnection and cooperation. The fact that such an informal structure can work must be understood within the strong Nordic tradition of cooperation in political and economic arenas, and the general trust that follows from similarities in culture and language. A more negative

view is that, even in such favourable circumstances, cooperative efforts have not succeeded in realizing all potential benefits: In the short-run, system marginal costs are not equalized among the Nordel countries. In a long-run perspective, cheap hydro in Norway has not been substituted for comparatively more expensive thermal power in the neighbouring countries.

43. We will summarize the main lessons from the Nordel experience as follows:

- Even when cooperation is limited to technical matters, substantial benefits can be gained: Nordel cooperation has centred on the sharing of information and know how, technical coordination, system stability control and short-run power exchange to increase system reliability. Even though each country has maintained policies of national control and self-sufficiency, and thereby severely limited the potential benefits from trade, it is clear that cooperative efforts have provided substantial gains to all parties involved.
- Gains from cooperation can be achieved even when arrangements are very informal: It is clear that the Nordic tradition of cooperation in many areas has been very important for furthering cooperation in the electricity supply industry also. However, another important reason for why such a loose arrangement can work may be the fact that the areas in which cooperation has taken place have been limited to those where mutual gains were possible without having to involve monetary compensation; rather than being a game of rivalry, the Nordel game has been one of coordination. Thus, cooperation may have worked, not in spite of, but because it was limited to areas in which the countries involved had, more or less, perfectly aligned common interests.
- Full cooperation may be difficult to achieve when agents are guided by goals other than profit maximization: To the extent that cooperation has not been completely successful, the most important reason appears to have been that economic efficiency concerns have been overridden by more traditional, engineering supply-security concerns. The current wave of deregulation and more reliance on market-based transactions, which occurred first in Norway, and is now under way in Finland and Sweden, seems to be changing this. An important argument underlying the 1990 Energy Act in Norway, as well as the new legislations in Finland and Sweden, was that market-based organization of the industry would lead to more efficient use of energy resources. Furthermore, with the low prices in the Norwegian market in 1992 and 1993, and more focus on profitability in the utilities, there has been much more interest in undertaking the necessary efforts to be able to export the electricity supply surplus at reasonable prices. If Sweden and Finland succeed in establishing market-based trade internally, there would seem to be good opportunities to extend cooperation and increase volumes of international exchange also.

44. Vertical separation between transmission and generation may be an important factor in promoting energy trade and third-party access: It would seem that much of the difficulties in obtaining access for wheeling through other countries have been caused by the grid owners dual interests as grid operators and producers/sellers of electricity. As a general rule, trade has been organized on a bilateral basis; eg. if a Norwegian generator wanted to sell power to TVS in Finland, this operation would involve first a sale to Vattenfall in Sweden, which would then resell the power to IVO (owner of the grid in the Northern part of Finland), which subsequently sold the power to TVS. All these bilateral trades would be on the basis of the 'split-savings' pricing and most of the gain would thus accrue to the middlemen, Vattenfall and IVO. Obviously, such an arrangement constitutes an important barrier to trade. With the separation of generation and transmission, first in Norway, and then in Finland and Sweden, it appears that such difficulties are now more easily solved. The Norwegian grid operator, Statnett, is currently discussing with its Swedish counterpart, Svenska Stamnät, how to coordinate tariff structures so as to facilitate trade between the two countries.

45. Deregulation in one (or more) countries will require reorganisation of the regional institutional framework, and will therefore give rise to transitional problems, but the long-term result may very well be to improve the prospects for regional cooperation: Even though the initial effect of the change of policy in Norway has been to create obstacles to Nordic cooperation, it seems very unlikely that these obstacles will not be overcome and that cooperation cannot continue with the same success as before. Already, Nordel seems to have accepted the new developments and both the organization and its focus has been changed accordingly. However, it is clear that some institutional changes will have to be made with regard to how trade is organized. It does not appear likely that one will move towards complete integration of the Nordel system, i.e. a common Nordic pool, and any institutional changes will therefore have to recognize national sovereignty and control over both transmission links and despatch. Two possibilities are (i) open access to both domestic and foreign agents in each of the national pools; or (ii) centralized power exchange between national pool operators. The former is already to some extent happening, as both Danish and Swedish buyers and sellers have access to the Norwegian Pool.

46. The Nordel electricity industries are still in a transitional period, with rapid changes to industry structure and regulatory framework taking place both in Finland, Norway and Sweden. At the moment, it is not completely clear exactly how regional cooperation will be organized in the future. However, the obvious common interests, and the stated commitments to regional cooperation, indicates that further integration will take place. It may be that the Nordel organization itself will become less important in the future, as more of the energy exchange and investment policies are delegated to the market. It would seem that the most important area for future cooperation is the coordination of transmission policies, including third-party access and transmission pricing. These problems are in the domain of the new and independent grid

companies, and already there are signs that these companies are organising their work outside of the Nordel organisation.

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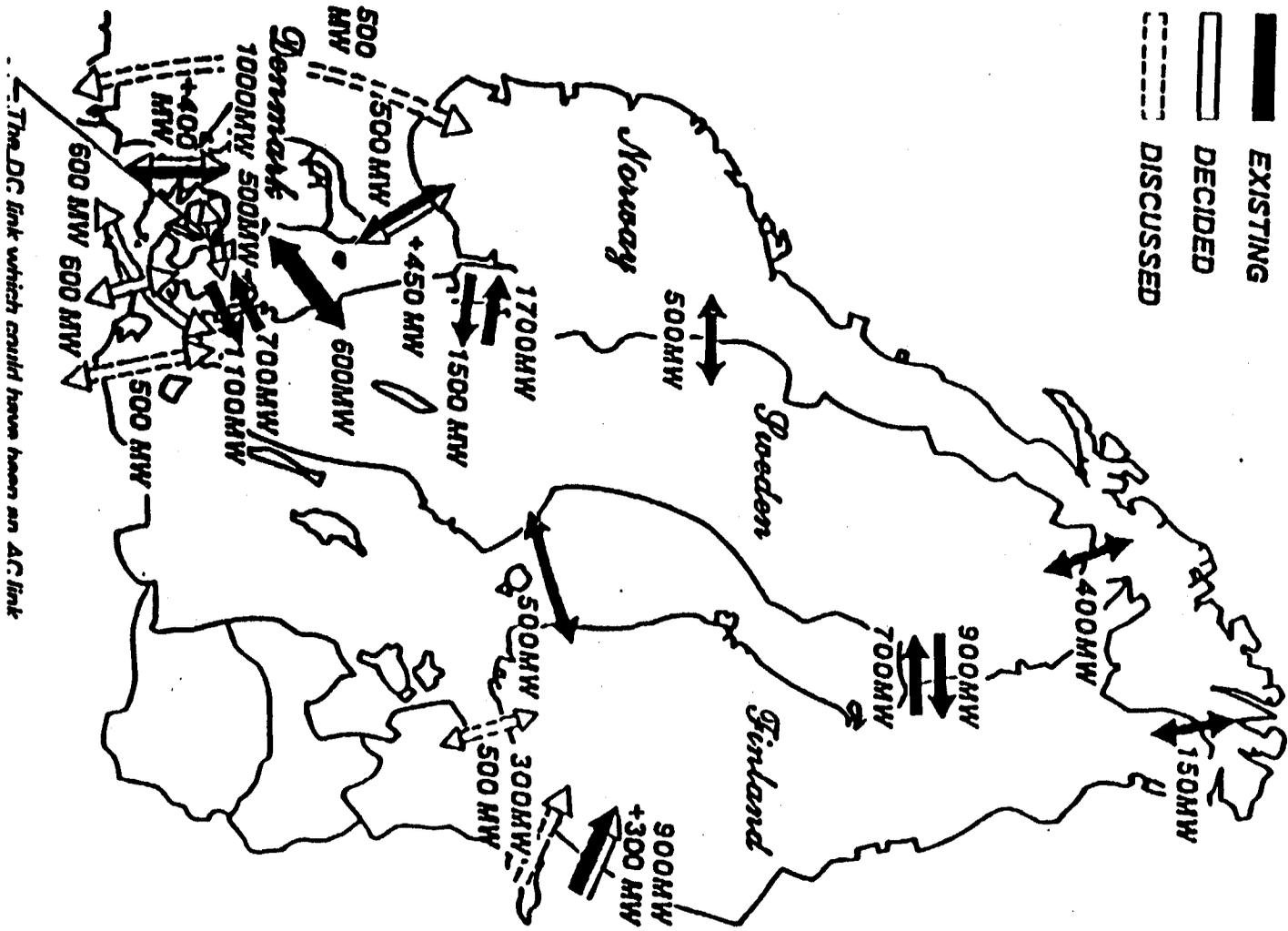
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South East Asia*

1. This case study was of much more restricted scope than the others, and concentrates particularly on the experience of Thailand and its interconnection with its two neighbours Laos and Malaysia. The brief visit enabled the identification of key issues concerning trade, but the analysis is necessarily less detailed than for the other case studies.

Advantages of South East Asia as a case study

2. Thailand has a well-developed power system, with an installed capacity of nearly 10,000 MW. It has physical connections with the small power system in Laos, and with the smaller but still substantial power system in Malaysia. These interconnections perform two different functions.

3. There are considerable hydro-electric resources in Laos, which can be and are being developed for use in Thailand. The connection with Laos is principally for this function. The connection with Malaysia is to allow opportunity trading between two well developed power systems.

The Power Sector

Thailand

4. The power sector in Thailand is organised in the form of a generation and transmission monopoly, the Energy Generating Authority of Thailand (EGAT). This sells electricity to two distribution authorities, the Provincial Electricity Authority and the Metropolitan Electricity Authority. The latter distributes electricity in and around Bangkok, and the former distributes electricity in the rest of the country. EGAT also sells electricity directly to some large customers. System expansion is rapid, with demand growth well in excess of 10% per annum.

* This case study has been investigated by Ian Pope, London Economics, Energy.

5. Table 4.1 shows the breakdown of installed capacity in Thailand by plant type.

Plant Type	Installed Capacity MW	%
Thermal (Steam)	5,507	50
Continual Cycle	2,860	26
Hydro-electric	2,416	22
Gas Turbine	238	2
Others	24	Small
TOTAL	11,045	100

Source: EGAT

6. From Table 4.1, it can be seen that Thailand has a predominantly thermal system. Because its economic development has been relatively recent, this plant is for the most part good, modern, high efficiency thermal plant.

7. The energy generation by fuel type is shown in Table 4.2 below.

Fuel	Generation GWh	%
Natural Gas	20,663	37
Heavy Oil	15,140	27
Lignite	15,081	27
Hydro	4,506	8
Purchases	511	1
Others	106	Small
TOTAL	56,007	100

Source: EGAT

8. From Table 4.2, it can be seen that hydro makes up only 8% of the total energy generation.

9. As to the future, EGAT anticipate that electricity demand in Thailand will continue to grow at very substantial rates in excess of 10%. They, and the Government of Thailand are proposing to deal with this by encouraging private sector generation projects, who will sell their output under contract to EGAT. Press reports indicate that up to 2,700 MW is proposed for private sector participation. EGAT will initially retain ownership of its existing plants, and will continue to operate the transmission system.

10. There are active considerations of privatising the existing generating capacity of EGAT. EGAT told us that this might be in about three years time, but press reports indicate a faster timetable may be in the Government's mind. Whenever this happens, EGAT is expected to retain its position as the operator of the transmission system and act as a monopoly wholesaler on behalf of the distributors. Currently, there are no plans to privatise distribution.

11. Thailand has a well-developed internal transmission system, with over 9,000 circuit km at voltages of 230 kV and above. The transmission system presents few constraints on the economic operation of the system within Thailand.

Laos

12. Laos has a small power system, with a maximum demand of around 90 MW. With the recent arrival of political stability in the country, growth in electricity demand is quite high at nearly 30%. The system within Laos is not fully interconnected, and is largely self-sufficient in terms of the generation available to supply itself. In addition, there is the Nam Gun hydro-electric power station of 300 MW, which was built exclusively to supply Thailand under contract.

13. The transmission system to connect the Nam Gun power station is separate from the rest of Laos.

14. There are significant further hydro-electric developments that could progress. Of these, 960 MW is being developed for export to Thailand.

Malaysia

15. In Malaysia, electricity is generated, transmitted and distributed by three vertically integrated utilities, Tenaga Nasional Berhad (TNB) in Peninsular Malaysia, the Sarawak Electricity Supply Corporation (SESCO) in Sarawak, and the Sabah Electricity Board in Sabah.

16. As in Thailand, the demand for electricity has been growing at 12 - 14% per year, and is forecast to grow at an average rate of at least 8% over the next ten years. The Malaysian

Government is actively pursuing private sector participation in new generation, and is looking at privatising existing parts of the supply industry, particularly through diversified ownership of power generation resources.

17. Continental Malaysia has a significant backbone in transmission, which has few transmission constraints. We understand there some voltage problems in supplying customers in the north of the country near the Thai border.

International connections

Current situation - Laos

18. Between Laos and Thailand the connection performs two functions:

- connection to the 90 MW Laotian system; and
- imports 300 MW from the Nam Gun hydro power station.

19. The capacity of the links are large compared with the size of the Laotian system, and therefore is fully capable of keeping the Laos system in synchronism. Indeed, the balance is such that the Laotians would have to try very hard to break synchronism.

20. The size differential is such that there is no possibility of any instability or generation shortfall in the Laos system being able to influence supply security in Thailand.

Current situation - Connections to Malaysia

21. There is a low capacity AC link between Sadao, Songkhla, Thailand and Bukit Keteri, Malaysia. There have been attempts to operate this link to synchronise the system from Thailand to Malaysia. The discipline of grid control on both of these systems is understood to be good, but unfortunately the capacity of the interconnector (about 100 MW) compared with the size of the systems meant that it broke synchronism on several occasions.

22. Because the link was small compared with the system, this breaking of synchronism was not an important event for either system but did have consequences on the security of supply to customers in the immediate vicinity of the link.

23. Since those attempts were made the link has been used to provide radial feeds to customers in the northern parts of Malaysia to overcome transmission limitations in the north of the TNB system.

24. Ownership of all the international interconnections is divided at the border and co-ordination is needed between the two countries for safety working when the line needs to be maintained.

Future developments - Laos

25. There is currently a proposal for 1500 MW hydro-electric of development in Laos to supply Thailand. A minute of understanding between the Governments has been signed, which includes a power purchase contract. The contract obliges the Laotians to develop the project and the Thais to purchase the output. As with the existing 300 MW Nam Gun development, a firm power contract is envisaged, and EGAT will have no role in the management of the reservoir other than to be aware of the reservoir levels for its own system security calculations.

26. The Thai negotiating argument with Laos is that the hydro is displacing efficient baseload thermal plant which would be EGAT's alternative option and therefore the output of the hydro should be priced at the baseload thermal price and should be firm power as from a thermal plant. It is thus a completely firm power contract.

27. We were not able in the time available to investigate the operating regime in detail, but this seems to imply that the vendors have to take a conservative view of the output of their plant, and then sell anything that is in addition as spill units at a short term spot price as a distressed seller. This is unlikely to lead to all the benefits of integrating hydro with thermal to be captured.

28. In particular, the following opportunities may be lost:

- to provide peaking power from hydro if this would be economic to do; and
- to develop more hydro resources that might be economic against a more realistic view of the value of hydro.

Future developments - Connections to Malaysia

29. A 300 MW DC link between Malaysia and Thailand has been approved by the World Bank for funding and has been agreed between the utilities. It is awaiting detailed approval from the Governments. The link will run from Klong Nhae, Songkhla in Thailand with Bukit Kayo Mitam in Malaysia. This DC link should enable the transfer of reasonable quantities of power without the need to overcome the problems of synchronising the two networks. The capital costs are shared (52% to Thailand) in proportion to the line length lying each side of the national boundary.

30. It is envisaged that this link will be used to exchange power on an energy banking basis. Both countries have some hydro resources and there are opportunities to transfer energy for subsequent use and transfer back. No formal contract is expected to be signed between the countries but it is envisaged that a protocol will be agreed covering the general principles of an opportunity trading system. We understand that both countries are expected to make full allowance for emergency reserve capacity that can be drawn through the link to be included as part of the portfolio of generation available in those countries to meet security of supply standards. In other words, full capacity credit is given for emergency supplies across the link.

31. A recent proposal to export gas to Thailand from Malaysia to fuel a 1800 MW combined cycle plant in Thailand has been abandoned.

Other regional connections

32. There have been considerations of further connections to Cambodia and through Cambodia to Vietnam. There is considerable hydro-electric potential in Vietnam which could economically be developed for export to Thailand (and some specific projects have been mooted by the Vietnamese). The peninsular Malaysian system is also connected to the system in Singapore from which we understand it imports power.

Environmental considerations

33. Environmental issues have fallen on heightened importance within Thailand. They have been very significant in the consideration of new plant capacity. In 1992, the Mae Noh lignite fired station (with only minimal air pollution control equipment) emitted excessive SO₂ quantities, causing injuries to local populations. This raised still further the environmental concerns in the country.

34. Further developments of hydro-electric resources in Laos (and possibly Vietnam) and to some extent interchange with Malaysia, will help to improve the environmental position of EGAT although this is not seen as the principal reason for investing in these links. However, the heightened interest in the environment also creates difficulties in obtaining wayleaves for new transmission line construction.

35. In the long term EGAT sees itself as a UCPTE type clearing house for clearing power throughout South East Asia. It sees this role as being consistent with its role in Thailand as a monopoly wholesaler and the operator of the transmission system.

Summary and conclusions

Benefits of the existing interconnections

36. The benefits of the existing interconnections with Laos are clear. The connection to the Laotian system provides Laos with considerable security of supply and access to a very large and well-disciplined system. It has no contractual rights to buy and sell electricity over the link but nevertheless opportunity trading probably achieves most of the benefits that could be achieved from this interconnection. We certainly understand that both systems give the link full capacity credit in their planning. The other use of the links with Laos is concerned with the output of a dedicated hydro station. The operation of the firm power contract is simple. Again we were not able to study the detailed operation of this contract but it appears to us that the concept of applying a firm power contract to a hydro plant feeding into a predominantly thermal system is almost bound to deny that thermal system some of the benefits of access to hydro plant.

37. The use of the AC connector to Malaysia has been constrained because of the inability to maintain synchronism reliably. Nevertheless the connection is used to provide supply reliability to customers in the north of Malaysia. This seems to be done on a very informal basis between the two countries but nevertheless this does appear to work. Neither government is involved directly in any of the trading. It should also be borne in mind that as far as Laos is concerned the export of hydro-electricity is the largest single foreign exchange earner and therefore the Laotian economy is very subject to the success of trading with Thailand. This puts Laos in a weak bargaining position.

Operation

38. We were not able to investigate the operation of the links in detail. Clearly the operation of a link of adequate capacity from a dedicated hydro plant is not a difficult task. Because the Laotian system is so small compared with EGAT and the size of the link relatively large compared with the Laotian system, Laos becomes in effect a small distributor connected to the Thai system and its operation has virtually no influence on the interconnected system. It would be difficult therefore for Thailand to perceive any operational difficulties arising from the connection to Laos and this is indeed so.

39. The AC link to Malaysia failed because of the difficulties of maintaining synchronism between two relatively large systems using such a weak link. This is not because of any fault in the operation of either system. It is merely that the control of the flows through such a weak link between two such systems is an impossibly difficult matter.

The contractual basis for trading

40. As stated in the previous section there is no formal contractual basis for trading between the system at large in Laos and Thailand and between Thailand and Malaysia. Trading is all of an opportunistic nature. Contracts are involved in the export of power from the 300 MW Nam Gun station in Laos to Thailand and in the proposed 1500 MW hydro development. The contract obliges the Laotians to provide firm power irrespective of the hydrological conditions. EGAT is not involved in the reservoir management. The contract includes significant penalty payments on the Laotians if they fail to deliver the supply reliably. To justify this, EGAT uses the argument that Laotian hydro has to be judged as an alternative to baseload CCGT plant in Thailand and therefore should be priced on the same basis and have the same contractual arrangement.

41. We have not done any calculations but we believe it likely that an economic evaluation would show more savings to be had from a greater installed capacity on hydros operating at a lower load factor with less security of supply. Firmness would still be sufficient to guarantee EGAT's security of supply and there would be savings to be had for equitable distribution.

Institutional linkage

42. Tradings over the links are arranged solely through bi-partite discussions. There are no formal arrangements through a trading body or any other central representative body representing the utilities in the area.

43. As far as EGAT is concerned, the Thai government does not appear to interest itself in these international tradings, and we understand the same is the case for Malaysia. Laos clearly has a closer interest between its government and the electricity sector, but nevertheless the government is forced to deal with EGAT rather than the Thai government.

Costs and benefits

44. We were not able to carry out a numerical exercise to quantify the costs and benefits of the various links. Clearly EGAT see the benefits of a DC link to Malaysia because they were prepared, with World Bank funding, to go ahead with such a venture.

Constraints

Financial, Economic and Technical Constraints

45. There appear to be no financial, economic or technical constraints on the use of the interconnector between Laos and Thailand. Between Thailand and Malaysia the interconnector is relatively weak and has not been able to be used reliably in the synchronous mode. It is therefore

constrained through technical factors to be used for radial feeding only. This is being overcome by the installation of a DC link. A much larger AC link could be installed and would be able to maintain synchronism but presumably this is not justifiable on economic grounds. Testing this assertion is beyond the scope of this case study.

46. There is plenty of hydro-electric potential in Laos that seems to be fairly cheap to develop but we believe that the very hard negotiating line taken by EGAT on the purchase of dedicated hydro may restrict the amount of future such development that takes place. EGAT has turned down any equity involvement in the development of the hydro resources in Laos. Presumably, the same problems will be encountered if the Vietnamese involve themselves in negotiation. There is also longer term scope for developing hydro-electric potential in Cambodia and Vietnam.

Institutional constraints

47. It could be argued that the inflexible contract between EGAT and Laos constitutes an institutional constraint on the further development of hydro-electric resources in the area. There do not appear to be institutional constraints on the construction and development of physical interconnections. EGAT seem quite willing to consider connection with Cambodia. We are not aware of the situation in Cambodia regarding this potential link.

Contractual constraints

48. Trading between countries is not covered by contract apart from the contracts to supply the hydro power from Laos.

Legal and regulatory constraints

49. In this quick study we were not able to identify any legal or regulatory constraints that would prevent further development of the interconnections between the countries.

Sector reform proposals

50. Thailand and Malaysia are moving towards a more open system with increased emphasis on private sector generation development and the privatisation of existing generating facilities. Both countries envisage an increase in the access of the grid system on a non-discriminatory basis to third parties. There are no formal proposals to extend this access across the national borders but in the present free market thinking of most countries in that region such a development would be natural.

Environment

51. There are environmental obstacles to the construction of new transmission in Thailand and this would apply equally to extending its international connections.

NEPOOL *

Overview

1. Formed in 1971, NEPOOL - the New England power pool - now consists of 96 electricity utilities in the six states of New England. It operates as a tight pool - with centralised dispatch, load forecasting and planning, shared operating reserves and coordinated maintenance scheduling. NEPOOL also has firm power, economy energy and emergency power purchase agreements with a number of other pools and utilities. The most important of these are interconnections with Hydro-Quebec, the New York Power Pool and the New Brunswick Electric Power Corporation.

Power and Energy

2. As Table 5.1 shows, the installed capacity of both utility and non-utility plant exceeded 25.6 GW in 1992. Hydro power (conventional and pumped storage) constitutes approximately 13% of capacity, Nuclear constitutes 25% of capacity and other thermal plant (mainly oil-fired) 60%. Net purchases of capacity make up 1.4% of the total.

	MW	%
Oil and Gas Fired	9869.87	38.50
Coal Refuse and Wood Fired	3817.32	14.89
Wind	0.10	0.00
Nuclear	6492.03	25.32
Hydro (Conventional)	1728.92	6.74
Pumped Storage	1668.85	6.51
Internal Combustion	1704.55	6.65
Net Purchases	356.05	1.39
Total	25637.79	100.00

Source: NEPOOL annual report, 1992

* This case has been investigated by Gil Yaron and Seabron Adamson, London Economics.

3. The energy requirements of NEPOOL's participants are illustrated in Table 5.2. In 1992, combined hydro generation provided some 7% of the 111 TWh of total generation, Nuclear provided 35% of generation and other thermal 59%. This year was atypical to the extent that nuclear generation increased by 4.1% on 1991, displacing oil-fired generation. Nearly 17% of total energy was provided by non-utility generators (NUGs) and 6% by imports from Hydro-Quebec. Over the past few years, up to 15% of total annual electricity demand has been provided by purchases from utilities in other regions.

Table 5.2 NEPOOL Sources of Energy for 1992		
	GWh	%
Conventional Hydro	5699	5.2
Pumped Storage	1749	1.6
Light Oil	363	0.1
Nuclear	38565	34.7
Coal	18226	16.4
Gas	13861	12.5
Residual Oil	21510	19.4
Wood, Refuse & Other	5253	4.7
Purchases	5917	5.4
Total Generation req'd	111222	100.0
Pumping	(2397)	
Net Load	108825	
Annual Load Factor		65.5

Source: NEPOOL annual report, 1992

Institutional structure

4. NEPOOL is governed by an eleven person executive committee, made up of one member representing:

- each of the eight largest investor-owned (private) utilities in New England;
- all the utilities in Vermont;

- several smaller investor-owned utilities; and
 - publicly-owned municipal and cooperative utilities.
5. The business of running NEPOOL is divided into three functional areas:
- Operations - New England Power Exchange (NEPEX);
 - Accounting and Settlement - NEPOOL Billing; and
 - Planning - New England Power Planning (NEPLAN).
6. NEPEX undertakes daily forecasting, scheduling and dispatch for the region. This occurs within a centralised control centre but utilises data provided by four satellite control centres spread across the six states (Connecticut Valley Electric Exchange, Maine Power Exchange, New Hampshire Control Center and Rhode Island-Eastern Massachusetts-Vermont Energy Control).
7. Agreed operating procedures are administered by NEPEX. These include special operating procedures designed to maintain system reliability within NEPOOL in the event of a severe generating shortage in New England or neighbouring regions. The ability to enforce action during a capacity deficiency (Operating Procedure 4, abbreviated as OP4) on the member utilities of NEPOOL (through interruptible supply contracts and voluntary load reduction) has been essential given the rapid growth in demand and resulting capacity shortage since the mid-1980s. While OP4 is usually applied to the region as a whole it has, on occasion, been restricted to parts of the region suffering a shortage.
8. NEPOOL Billing monitors and accounts for all power supply transactions within NEPOOL and between NEPOOL and other networks or utilities. This includes accounting for energy services such as scheduled and unscheduled generator outage services provided to participants. It has a critical function in ensuring that all costs and benefits of power pooling are shared equitably among the member utilities. Its activities are funded from the savings made by pooling. NEPOOL billing costs are around \$3 million per annum.
9. NEPLAN provides both short-term (up to 3 years) and longer-term energy demand forecasting for all members. It also has responsibility for studying and evaluating future generation and transmission plans proposed by participants as well as developing and recommending reliability standards for the NEPOOL system.

Growth of Energy Trading

10. The rapid development of NEPOOL is illustrated in Figure 5.1. Energy supplied by NEPOOL has more than tripled since the pool was formed in 1971 - rising from 5.1 TWh to 15.6 TWh in 1992 - an annual growth rate of approximately 9.7%. This is only energy supplied by the pool - total generation is much higher.

Contractual Details

Institutional arrangements

11. The New England Power Pool Agreement runs to over 200 pages and provides a very detailed institutional framework for NEPOOL. Despite this it is sufficiently flexible to allow very small municipal and very large investor-owned utilities to participate, and for membership across states with different power sector legislation. The specified objective is to:

- "assure that the bulk power supply of New England and any adjoining areas served by Participants conforms to proper standards of reliability; and
- attain maximum practicable economy, consistent with such proper standards of reliability, in such bulk power supply and to provide for equitable sharing of the resulting benefits and costs".

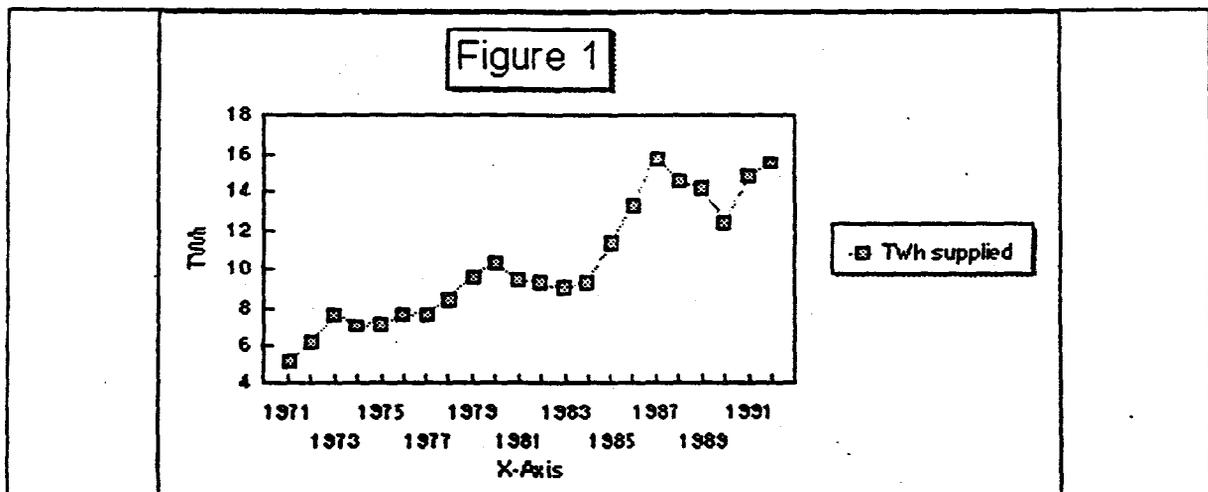


Figure 1 The Growth of Energy Supplied by NEPOOL

12. The Agreement itself contains only limited detail on operational procedures. There is typically a statement of *what* these procedures are intended to do, with the details of *how* this is to be achieved being left to the relevant committee. Centralised dispatch, for example, is to be undertaken to meet system reliability objectives at lowest practicable cost - with NEPEX and the operating committee left to specify the details. Given this approach, considerable attention is paid to defining the role and responsibility of each committee.

13. As this structure has succeeded in maintaining the pool it is worth spending a little time considering how it works.

14. The management committee is the principal policy-making and dispute-resolution body (as it hears appeals to the decisions of any other committees). All participants are members with additional seats given to the very largest utilities.¹ Voting is in proportion to the participant's annual peak demand but requires a high degree of accord. Decisions require 75% support with less than 15% in opposition. An executive committee is elected from the management committee to undertake regular oversight of the running of NEPOOL.

15. Operations and planning committees report to the management committee. Membership of both is only partially related to generating capacity: any participants with more than 3% of annual peak demand gain membership. The very largest utilities gain additional members (as for the membership committee) with small investor owned and municipal participants each getting one representative.

16. The operations committee has responsibility for:

- scheduling and coordinating through NEPEX the bulk power supply of Participants;
- ensuring operating reserve and system of NEPOOL;
- maintenance scheduling;
- NEPEX operation;
- setting standards for equipment;
- determining the summer and winter capabilities of each generating unit;

¹ An extra seat is given for each 10% of total peak capacity in excess of 20% provided by a Participant.

- determining the annual peak, adjusted annual peak and capability responsibility of each participant;
- calculating incremental and decremental (avoided) costs;
- determining appropriate billing procedures;
- calculating and apportioning losses from NEPEX transactions; and
- determining rules for cogeneration.
- Decisions require a two-thirds majority of members present. In contrast, the planning committee does not vote, but prepares recommendations for the management committee. The planning committee has responsibility for:
 - recommending reliability standards;
 - collecting and collating load forecasts from each participant; and
 - evaluating alternative NEPOOL expansion programmes.

Operational details

17. Although operational procedures are not specified in great detail, there are important sections of the Agreement which relate to operational responsibilities of Participants and how costs and benefits are to be divided.

18. Each Participant (which can mean a single utility or group of smaller producers) is required to provide sufficient capacity - its capability responsibility - to meet their expected load (defined with reference to both past annual and monthly data). This can be provided by owned plant or via firm contracts for capacity. Failure to meet the capability responsibility is punished and additional excess declared capacity rewarded accorded to conditions laid down by the operating committee.

19. Given this declared capacity, the agreement specifies that all plant is dispatched by the central control centre with the objectives of meeting system reliability at lowest practicable cost.

20. Operating reserve provided via the pool is classified (and charged) on the extent to which it is scheduled. The general charging structure for pool energy services - from highest to lowest - is specified to be:

- energy provided to non-Participants (excluding Hydro Quebec);
- energy for Hydro Quebec banking or pumped storage of participants;
- energy to cover unscheduled outages in excess of a participant's capacity entitlement ("deficiency service");
- unscheduled outages to the limit of the capacity entitlement;
- scheduled outages; and
- economy flow service from entitlements in units, available but not scheduled for operation.

21. Charges are based on incremental cost, with the exception of economy flow service which is charged at avoided cost.

22. Each pool participant has to permit open access to their transmission facilities for other participants utilising the energy services listed above. Payment for use of EHV transmission facilities is based on generating capacity with separate wheeling charges (based on fictional contract paths, not actual load flow paths) for trade with non-participants (eg Hydro Quebec).

23. At present these wheeling charges are less than comparable wheeling charges for other utilities in the United States. NEPOOL recognises that the present charges do not reflect true marginal costs of transmission; wheeling charges are being reviewed by a regional transmission group. This issue is receiving substantial attention across the United States due to an expected ruling by FERC (the Federal Energy Regulatory Commission).

Benefits and Costs of Trade

24. The primary gains from trade have arguably been the ability to provide a reliable service in an environment of rapid load growth and excess demand. These gains are difficult to quantify independent of saving from economy exchange, etc. without considerable computer modelling. Given the small size of many New England power systems it is clear that there are considerable benefits, however.

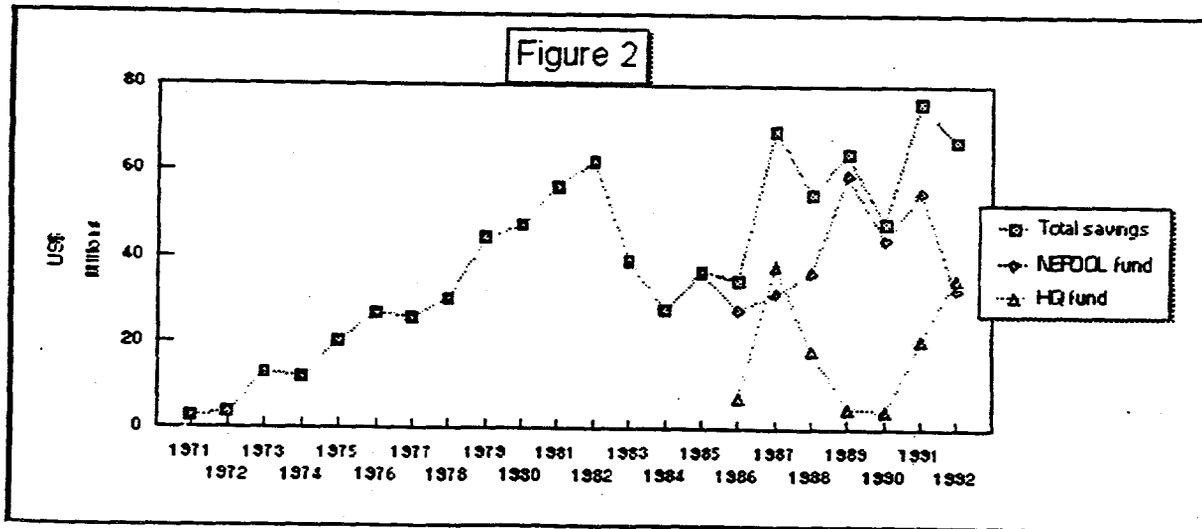
25. The gains from centralised dispatch and electricity trade between NEPOOL members create the NEPOOL savings fund. NEPEX calculates the costs of meeting demand using individual cost data for each utility (i.e. fuel and variable O&M costs) and for the centralised dispatch. Software then calculates the electricity trades necessary and the savings from central dispatch. Participants pay for energy at their incremental cost, while suppliers are paid at their avoided cost; the difference is goes into the savings fund. For historical reasons the savings are

then rebated back to the utilities (minus some of the costs of running the pool) based on the savings each has accrued over the period.

26. An additional form of savings arises from trade with adjacent power pools. Transactions with Hydro Quebec have risen rapidly since the mid 1980s to form the vast majority of trade (85% in 1992), with the New York Power Pool and the New Brunswick utility providing the remainder. The large interconnector with Quebec was a joint project between a number of utilities. Users either own equity stakes in the project or lease access from others. Utilities can sell their shares or rights to others. The interconnector with New York is wholly owned by Northeast Utilities, which leases access to other utilities.

27. As Figure 2 shows, the gains from trade with partners outside NEPOOL have risen to the stage where they equal internal gains from tight pooling. Savings made by trades with Hydro Quebec form the HQ fund, which is also shown in Figure 2.

28. a pool - to maintain adequate reliability. This was especially valuable during the mid-1980s, when demand growth was high in New England. The environment of rapid load growth and excess demand has contributed to the need for. While this helps to explain the success of pooling, but not the degree of coordination achieved.



29. The decline in savings from intra-pool since the late 1980s is attributed to participants seeking trade with non-participants (non-pool members). This follows excess supply within the pool and lower prices. Excess supply has resulted because of:

- recession thus lowering demand;
- new capacity coming on stream; and
- large demand side management programmes starting to reduce demand.

30. NEPOOL is unusual in that it conducts centralised dispatch outside of the control of member utilities. This is necessary given the large number of participating utilities (98 currently). In contrast, a fairly tight pool such as PJM has eight. The large number of members precludes each announcing its chosen plant schedule in advance - if any gains from coordination were going to be made it had to be through very close coordination.

31. The large membership of NEPOOL lies in the many small municipal utilities which have joined. Initially small municipal and private utilities were excluded from the pool but legal action forced their inclusion. Empirical evidence suggests that small utilities gain most from pooling, so the incentive to join the pool was clear.

32. The costs of operating the pool amount to some 15-20% of Pool Savings, ie roughly \$US 10 million. Approximately half of this is taken by NEPEX, a quarter by NEPOOL Billings and a quarter by other management functions. Only half of these expenses are paid from pool savings. The other half is paid directly by utilities.

Structures and Constraints

33. This section will concentrate on the economic circumstances and institutional structures which have made NEPOOL a relative success among regional power networks. NEPOOL has been constituted as a tight pool and, as such, has overcome the constraints facing other regional power networks. The roots of its success are hypothesised to lie in the magnitude of potential savings possible from regional power cooperation and the institutional structure developed to harness this potential. These will be discussed in turn.

Potential Economic Gains

34. The magnitude of net benefits to NEPOOL member utilities have been due to:
- large potential gains from coordination that existed - internal transactions have produced savings of more than \$US 730 million, although many of these savings might have been possible with a looser pool structure if this had proven practical;
 - gains from trade with Canadian (hydro-based) utilities which have been far easier to realise by negotiating as a Pool rather than establishing individual power and wheeling agreements. Trade with Hydro-Quebec alone has provided NEPOOL members with savings of more than \$US 130 million since 1986; and
 - necessity of reliability standards being met in an environment of capacity shortage. Pooling offered a very cost-effective means of achieving this requirement. This is probably the most important of the economic factors.
35. While economic arguments explain the use of pooling, institutional factors are central to the formation of a tight pool. These are discussed below.

Institutional Structures

36. Utilities in the USA are vertically integrated, and are generally confined geographically to one state. This is primarily the product of the regulatory structure in the USA, under which public service monopolies are regulated by state public utility commissions. New England, due to the small size of the states and its history of decentralised government, has a particularly large number of utilities in a small area. The legal decision that small municipal utilities could not be excluded from NEPOOL significantly increased the number of potential participants.
37. The institutional structure of NEPOOL has been determined by the large number of utilities involved (particularly after the municipal utilities joined) and by their characteristics. Not only are utilities in New England diverse, they differ greatly in size, customer and generation mix, and other characteristics. NEPOOL includes large utilities such as Boston Edison, for example, as well as small municipal electric departments serving isolated villages in Maine and Vermont.
38. Two consequences for the institutional structure of the pool can be derived from the large number (and diversity) of the participating utilities. First, the creation of NEPOOL focused not on operational procedures but on institutional arrangements. As was noted above, the agreement setting up the pool contains little guidance on day to day operations. Instead, the organisational structure and responsibilities of the various committees is detailed, with resulting flexibility for

revising procedures to meet new requirements. This has allowed NEPOOL to successfully integrate new members, shift much of its attention to negotiating imports from Canada, and meeting other challenges. While this legalistic structure comes at a price, it has given the pool the basic organisational ability to change in the face of new pressures.

39. Second, the number and diversity of participants ruled out dispatch using each utility's chosen schedule (as done by PJM). Fully centralised dispatch was required, and NEPOOL was chartered as a tight pool.

40. The objective of tight pooling was facilitated by legal and contractual structures. Specifically:

- the regulatory structure across the six states of New England was workably similar, and the regulatory commissions were cooperative;
- utilities could trust that disputes could be settled by the management committee or as a last resort that contractual agreements could be enforced by law;
- the careful attention to organisational design in the NEPOOL agreement allowed all members to have representation but enabled those utilities with most at stake to have the dominant share of votes in decision taking; and
- the vertically integrated utilities are not in competition with each other and had little to lose from close cooperation with other utilities.

Constraints

41. Despite having achieved a high degree of coordination, obstacles do remain for the expansion of NEPOOL. The trade with adjacent pools, (Hydro Quebec in particular) is formalised to the extent of loose pooling. Constraints on expansion have prevented these links evolving into a tighter structure.

42. The possibility of expanding NEPOOL to incorporate utilities in New Brunswick and Nova Scotia in maritime Canada has been investigated. Economic benefits were found to exceed technical costs. The chief obstacle to this integration has been institutional. Specifically, the addition of utilities outside the United States would entail new regulatory problems and costs. The difficulty of meeting a combination of local, federal and international (Canadian) regulation is felt to outweigh the economic benefits that could be realised. This has posed a limiting constraint on the expansion of NEPOOL to the north. To the west is the New York Power Pool, which has already evolved its own pooling structure.

Environment

43. No precise details were available on the reductions in emissions made through pooling in New England. Pooling has helped utilities to utilise capacity more efficiently, generating more of total energy from nuclear and hydroelectric plant. Since much of NEPOOL's peaking capacity is oil-fired, trading has allowed sulphur emissions to be cut significantly. This has helped NEPOOL members to meet strict Clean Air Act requirements at a lower cost.

44. The second main environmental benefit has probably been reducing the demand for new plant and transmission lines through trading. In a relatively densely populated area of the United States (and a region where environmental concerns are a priority on the political agenda) this may rival reductions in emissions as the chief environmental benefit. NEPOOL now estimates that expansion of the current 345 kV network will provide sufficient transmission capability for the foreseeable future. This is of considerable benefit as siting of transmission lines has become increasingly difficult and expensive in the region.

MAPP*

An Overview

1. The Mid-continent Area Power Pool (MAPP) is a voluntary coordinating organization but without centralized dispatching and consisting of 44 electric utilities. The MAPP region encompasses nearly a million square miles: it extends from the Canadian border of Manitoba and Saskatchewan to Iowa and Nebraska's southern borders and from central Montana to central Wisconsin. About thirteen million people live in the MAPP region. MAPP's summer peak has been over 30,000 MW in 1994 and its total generating capacity is about 40,000MW. Most of the energy production comes from coal (58%), followed by hydro (24%), and nuclear (17%), with the rest from oil/gas and other sources. In MAPP-Canada 99% of generation comes from hydro sources.
2. MAPP's goal is to ensure that the region's interconnected bulk electric system is operated reliably and efficiently and reducing as much as possible the environmental impact, in compliance with the North American Electric Reliability Council (NERC) operating guides and criteria.
3. Unlike any other in the nation, the MAPP organization is both a power pool and a reliability council. MAPP members agree to follow strict procedures to ensure adequate reliability and quality of service for consumers in the region. Member also agree to buy and sell electricity among themselves to provide their customers with the most economic electric service available.
4. One of the functions of the MAPP center in Minneapolis is economic dispatch of the bulk power system within its region. Every hour of the day, the computer at MAPP headquarters transact the sale of electricity from the various companies wishing to buy or sell electricity. This MAPP Bank was the first automated brokering program in the country. MAPP members utilize the Procedure to Optimize Economy Transactions or POET program which matches low-cost sellers in the region with high-cost buyers. Brokering serves as the final fine-tuning of the regional system before the hour in which the load must be met.
5. MAPP members have pledged to work together to achieve the highest reliable system operation and lowest cost electricity for consumers. This is accomplished by coordinated long-term planning as well as in daily operations. Through their coordinated planning, MAPP members have agreed to jointly monitor and assess the conformance of

* This overview on MAPP has been prepared by ESMAP.

their combined plans with a commonly accepted and consistently applied set of planning criteria, and perform at regular intervals such joint studies, assessment, investigations, etc., to secure conformance with the criteria. This is again in line the NERC guidelines for 'coordinated planning'.

6. Essentially the obligation to members who are signatories to the MAPP agreement consists of the following:

- assist other members in emergencies;
- main the minimum generating reserve;
- permit wheeling for other members up to safe limits;
- connect to the MAPP Communications Network;
- adhere to the terms of the MAPP agreement;
- furnish information for planning and operations;
- follow the established Operating Standards and Requirements; and
- assure new facilities and facility upgrades will not degrade reliability with the overall system.

7. MAPP faces many challenges as the electric power industry experiences great changes brought about by restructuring of the way it does business. However, reliability, efficiency and economy remain the key goals of MAPP. The industry is engulfed in issues regarding increased competition as the Federal Energy Regulatory Commission (FERC) has mandated wheeling under the Energy Policy Act of 1992. The Energy Policy Act also challenged NERC to ensure its policies are open and equitable so its Reliability Criteria and Principles will continue to be those that are consistently applied in the industry.

8. Changes are not only being encouraged at the federal and national levels. While in years past utility planning could be described as capacity planning, now regulatory forces are requiring utilities to submit integrated resources plans (IRSs), stressing a balance of supply-side and demand-side options. These least-cost plans have an effect on required reserve margins and require the most efficient use of the interconnected system. These new requirements directly impact the MAPP organization and its goal of coordinated planning.

9. The entering of MAPP into the IRS arena and increase environment concerns demand alternate energy choices in the near future. Wind, solar and run-of-river generating plants may someday be a more significant part of the MAPP generation mix as it is today. MAPP members has approved procedures for accrediting variable capacity in anticipation of its stronger presence in the region.

10. It is clear that the increased wheeling, fostered by increased competition, will increase the number of users of the transmission system, and the number of inter- and intra-control area transactions that must be managed by MAPP. This will increase the complexity and challenges of properly controlling the bulk electric system, especially during emergencies.

11. As wheeling increases, electric transfers will increase. Since these transfers follow the 'path of least resistance' governed by the laws of physics, not contract law, they may use up the transfer capacity of already heavily loaded portions of the system and the capability planned for future load growth, and in the extreme, overload critical facilities.

12. Finally, increase competition may hamper the exchange of information and technical data that are essential to coordination of system planning and operation. Without this coordination, the long-term reliability of the bulk electric system may be jeopardized.

13. There are great challenges for MAPP as it readies itself to meet current and future changes. In this new environment, MAPP members have reaffirmed their commitment to provide reliable and economical service and to increase the efficiency of the interconnected system.