

**UNITED STATES OF AMERICAN
FEDERAL ENERGY REGULATORY COMMISSION**

**Electricity Market Design and Structure
Docket No. RM 01-12-00**

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**LESSONS FROM THE INSTITUTIONAL FRAMEWORK OF TRANSMISSION,
SYSTEM OPERATION, AND ENERGY MARKETS IN MOST WEST EUROPEAN
COUNTRIES AND SOME OTHER COUNTRIES –
THE CASE FOR TRANSCOS**

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1. INTRODUCTION AND SUMMARY

In its recent orders regarding the Alliance Companies and National Grid USA (Docket Nos EL02-65-000 and RTO1-88-016) and regarding Translink Transmission Company, LLC (Docket No. EC01-156-000, et al) both of 25 April 2002, FERC indicated that “the ITC business model can bring significant benefits to the industry”. We welcome this support for ITCs because we believe that they - *and more so wide area transcos* (i.e. stand alone companies that are both transmission asset owner and system operator across a significant proportion of a market area) – can play a major role in providing the necessary infrastructure for operating wide area power markets. We also welcome FERC’s comments that “The decisions we are making today regarding the division of responsibilities between ITCs and RTOs are not set in stone”. We believe that there are some fundamental misconceptions about the relationship between the functions of system operation, operating an imbalance arrangement¹, and operating a day ahead market, and also of the nature of nodal² “locational marginal pricing” (LMP). If these misconceptions are allowed to persist they could foreclose organisational options and unnecessarily limit the scope of transcos.

Due to the legacy of history, the design of the transmission network in many parts of the US is not as well suited to running markets as in European countries where national transmission systems were generally developed to enable nationally optimised dispatch. In contrast in the US, with the exceptions of the PJM area and New England and New York which have a long tradition of joint planning, the networks have generally been designed to serve the native load of utilities and to connect to neighbouring utilities for reliability support, not to provide the basis for wide area power flows. Thus, for example, the transmission network in California is not designed as an integrated state wide network, but is really five separate systems that are basically designed to serve the needs of integrated utilities and distributors with long term supply contracts. The systems are not generally strongly interconnected and can suffer from serious congestion when they are not operated (as has been the case following the introduction of the market) in the manner for which they were designed.

The proper organisation and pricing of transmission and a strong network are a necessary (but not sufficient) basis for the successful development of competitive electricity wholesale and retail markets. Yet in the US transmission has often been treated as the Cinderella of the industry. It has

¹ We use the word “arrangement” as a generic term to cover both a market and also quasi- and non-market arrangements used in some jurisdictions.

² In the US “LMP” has been equated to *nodal* marginal pricing. In fact multi-zonal pricing is also “locational” and is likely to be marginally based, and so is also “locational marginal pricing”. In this paper we use LMP in the US sense.

frequently been caught up in deals (such as recovery of stranded costs or merger negotiations) whose immediate financial significance is of much greater concern to company chief executives and shareholders than the small fraction of value represented by transmission. Furthermore, in our opinion the US debate on restructuring has focused too much on the means for *measuring* the cost of congestion. Although the issue of the precise methodology used to measure and signal the consequences of congestion to market participants is a matter for consideration, it is at best of secondary importance to other issues that should have been on the table, notably:-

- how to *manage* congestion³ in the active sense of the word of maximising network availability to reduce congestion costs
- how to develop networks to ensure that they provide the necessary infrastructure for running wide area markets

It is important to appreciate that generally a stronger grid is needed to operate a successful wholesale market than is required by a centralised “command and control” cost based system. In a cost based system the costs can be minimised and there is no potential for the exercise of market power. In a market; generators can not only exercise market power in export constrained areas, it is often possible for portfolio generators to create artificial constraints and then to exploit them. Thus both to reduce the scope for the exercise of market power and to build the scope of the workable market it is necessary to “overbuild” transmission compared with a cost based system.

Our paper aims to assist FERC in developing its thinking by setting out in section 2 and supported in Annex 1 the ways in which most of the west European countries have structured the institutional framework of transmission, system operation, imbalance arrangements and energy markets when they liberalised their wholesale electricity market. Generally their approaches have been very different to the proposals in FERC’s recent Working Paper on “Standardised Transmission Service and Wholesale Electric Market Design” (The Working Paper). Thus in western Europe:-

- all of the countries have transcos, most of which are stand alone companies entirely independent of generation and retailing, and some of which are privately owned including three which have their own stock market quotations. Most have a responsibility for developing their networks with a formula method for allocating the consequential costs

³ “The management of congestion” has two distinct meanings which can cause confusion. The first is the process of resolving constraints whereby the system operator modifies the pattern of generation (and possibly loads) to keep within security constraints The second meaning is the active sense of the word “management”, viz to reduce or to control the costs of congestion by influencing the behaviour of generators and loads through contracts and by managing (active sense again) the availability of transmission. We use the words in this sense.

- except for France all markets are decentralised in allowing generators to self-dispatch
- none use LMP to measure the cost of congestion
- scheduling coordinators are expected to provide balanced schedules by price zone. All except one transco operates an imbalance arrangement, but only two are imbalance markets comparable to the US concept, while two are not intended to be markets. In England & Wales the role of system operator is clearly separated from that of an arrangement to settle imbalances
- only one transco operates a short term forward energy market, and the reason for that was to secure the market financially
- three have regulatory frameworks that incentivise the reduction of congestion by the transco

To provide further experiences, in section 3 and supported in Annex 2 we also examine the institutional frameworks in Argentina, Australia and New Zealand. Two operate LMP systems, while the third operates a zonal pricing system. One operates a day-ahead market. Two have ISO like organisations, while the third (New Zealand) has a transco *which provides the data to another organisation that operates a market based on LMP.*

We recognise that the ISO structure is necessary where transmission ownership is balkanised and is part of integrated companies. But in section 4 we argue that the structure fragments the provision of a transmission service between the ISO and the transmission owners, and neither provides a “joined-up” service. In consequence:-

- there is no clear incentive on any party to either *manage* congestion in the active sense of the word of controlling and reducing it, nor to procure ancillary services efficiently
- there is generally no clear responsibility for planning the economic development of the network, and no direct incentive to invest because the parties that bear the cost of congestion may not have the means to mitigate it

We think that some of the arguments that have been advanced in the “slicing and dicing” debate show a lack of understanding of market design in other countries, and are also based on misconceptions that wrongly conflate the functions of system operator with that of operating an imbalance arrangement and a short term forward energy market. In section 5 we explain that the function of system operation is to ensure that the system operates reliably at minimum very short run cost, but that fulfilling this function does not require knowledge of LMPs which are in fact generated as a by-product of operating the system. The data required can be taken from the system operator and used by another organisation to calculate LMPs (or some other methodology) and to

run an imbalance arrangement. *The functions of system operation, publishing LMPs, and settling imbalances can be unbundled.*

We think that FERC has invested too much significance in LMP – *it does not manage congestion, it measures it.* Although conceptually it is the most accurate way of measuring congestion there has to our knowledge been no empirical analysis of the significance of inaccuracies and welfare loss from using other methods of measurement. *We believe it is more important to manage congestion than to measure it at every node.* Furthermore we are not convinced that LMPs either on their own or hedged by transmission congestion contracts will generally provide correct signals to incentivise transmission expansion, a view which we support with a simple example in Annex 3.

Moving forward we suggest FERC’s priorities should be to:-

- incentivise the development of more transmission where it is appropriate to do so and in as market oriented manner as is possible
- incentivise the maximum use of the existing network to reduce the costs of congestion, which can be achieved by introducing effective PBR incentives

To get sufficient transmission developed requires dedicated transcos who (within an appropriate regulatory framework incentivising efficiency) “will go for it”. We thus suggest that the Order which results from the Working Paper should encourage the development of wide area transcos. They would own assets and as system operator would control the system from say an hour ahead down to real time and to that end would handle congestion, losses, and ancillary services to the extent that market participants do not self provide. *The decision whether or not the transco or some other organisation independent of market participants (e.g. an RTO) operates a real time imbalance market and a day ahead energy market is an issue of no great importance.*

We further suggest that there should be an attempt to move in part from centralised transmission planning to a more user oriented approach which is market driven and incorporates the incentive for both efficient operation and development. To this end we have developed a new approach which is based on the concept of “transmission access contracts” between the users⁴ and the transco (and in some circumstances might be with other parties). In return for a payment the contracts would define a level of access to the shared network coupled with a predefined level of compensation if that access is not provided. We explain the concept on p19.

⁴ Users are defined in England & Wales as generators connected directly to the high voltage grid; end-use customers connected directly to the high voltage grid; distribution networks connected to the high voltage grid; and retailers.

To ensure that the transco is efficient it must be subject to an appropriate regulatory framework which might include a PBR scheme for its operations and maintenance costs; should include a PBR scheme for system operation costs; surveillance of the construction of any lines built on a regulated basis; surveillance to ensure that other parties wishing to build merchant facilities are not obstructed; market monitoring and compliance; determining market rules and resolving disputes; ensuring that transcos/ITCs/transmission owners provide a non-discriminatory service; and approving tariffs including arbitrating on transmission access contracts. We think that FERC will have to assume a more active regulatory role than traditionally to ensure that sufficient transmission is built and that it is utilised efficiently.

We believe the transco package we have outlined offers FERC the prospect of an efficient market oriented transport business, which has incentives to operate the network efficiently and to develop it, and is user oriented.

2. ORGANISATIONAL ARRANGEMENTS AND MARKET DESIGN IN WESTERN EUROPE

Over the last twelve years, commencing with England & Wales and followed by Norway, major west European countries have restructured their electricity industries to introduce competition. In annex 1 we provide details of the arrangements, which are summarised in exhibit 1.

A common feature in all these countries (and also in Portugal, the Republic of Ireland, and soon Belgium) is that the transmission asset owner is also system operator – they are all “transmission system operators”⁵ or “transcos” in US parlance. In all countries except Germany they are national in scope and they inherited strong networks that were designed to operate a national merit order, and which are in many cases reasonably interconnected with neighbouring countries. In all countries except Germany and France the transmission system operators are stand alone corporate entities completely independent of generation and retailing. Some are privately owned companies and three (perhaps five in the future) have stock market quotations, while the others are publicly owned. Most have a responsibility for developing their networks and to facilitate development they have a formula method for allocating the consequential costs, and in the case of the National Grid Company (NGC) in England & Wales, TenneT in the Netherlands, and Red Electrica in Spain their regulation is designed to permit – if not to incentivise – investment in the shared network. Thus over the last

⁵ This term is now used throughout Europe for a transmission asset owner cum system operator. There is now a European Association of Transmission Operators, ETSO.

Exhibit 1 Organisational arrangements and market design in western Europe

	Owner	Transmission network Ownership	Development	System operation	Centralised dispatch or not	Imbalance arrangement Operator Mkt or not	Short term energy market	Measure congestion
Germany	four integrated companies	private	the TSOs	the TSOs	no	the TSOs	yes European PX Leipzig PX	effectively 1 zone
Italy (proposal)	TERNA/ GRTN	private	TERNA/ GRTN	TERNA/ GRTN	no	GRTN	quasi GME	expected initially 1 zone
France	RTE	government	RTE	RTE	centralised	RTE	no Powernext	
Nether- lands	TenneT	government but may be privatised	TenneT	TenneT	no	TenneT	quasi Amsterdam PX (owned by TenneT)	1 price zone
Spain	Red Electrica	private	Red Electrica/ other owners	Red Electrica	no	Red Electrica	no OMEL	1 price zone
England & Wales	NGC	private	NGC	NGC	no	BSC Panel/ Elexon	no UKPX and APX	1 price zone
Norway	Statnett	government	Statnett	Statnett	no	Statnett	yes NordPool	1 or 2 price zones
Sweden	Svenska Kraftnät	government	Svenska Kraftnät	Svenska Kraftnät	no	Svenska Kraftnät	quasi NordPool	1 price zone
Finland	Fingrid	government	Fingrid	Fingrid	no	Fingrid	quasi NordPool	1 price zone
Eastern Denmark	Elkraft	LDCS	Elkraft	Elkraft	no	Elkraft	quasi NordPool	1 price zone
Western Denmark	Eltra	LDCS	Eltra	Eltra	no	Eltra	quasi NordPool	1 price zone

Note – “quasi” means that they are not supposed to be used as markets of last resort as scheduling coordinators are supposed to provide balanced schedules. In all quasi cases there is one price for being short and another for being long as described in the Finnish section in Annex 1.

decade NGC spent an average of \$320m p.a. on developing the shared network as compared with a forecast of \$95m p.a. by the PJM⁶, which prior to the recent extension of PJM West was a similar size to the system in England & Wales⁷.

Market design

Turning to market design, all of the arrangements are fundamentally different from FERC's thoughts in the Working Paper:-

- only the French system is centrally dispatched
- none of the countries have adopted LMP – they are all “zonal markets”; indeed, with the exception of Norway each country is a single price area
- physical market participants (i.e. generators, traders, and retailers) are expected to provide balanced contract schedules of injections into and takes from each price zone. In Norway and Germany the system operators run a single clearing (i.e. marginal) price imbalance market, while in Italy, Netherlands, Sweden, Finland, and Denmark the transcos do not operate an imbalance market in the US sense but a dual cash-out arrangement based on the clearing (i.e. marginal) prices of buying regulation-up and –down, which is described in the Finnish section of Annex 1. The imbalance arrangements in Spain and England & Wales are not intended to be markets. In England & Wales the National Grid Company (NGC) does not operate the imbalance settlement and charging arrangements. Its role of system operator (for which it runs procurement markets to buy the services it needs to balance the system) is clearly separate from that of both the governance of the imbalance arrangements and from the administration of the settlement of imbalances, which is undertaken by ELEXON. *This is a point of considerable significance to the “slicing and dicing” debate – namely it is possible to clearly separate the functions of the system operator, which is concerned with ensuring the electrical balance of the system at least cost, from those of the imbalance operator, which is concerned with charging for discrepancies between contractual positions (which are of no concern to the system operator) and metered volumes injected and taken from the transmission system by market participants.* An outline of the relationship between NGC's procurement markets and the settlement and charging for imbalances is shown in exhibit 2
- only one transco operates an energy market, namely TenneT in the Netherlands which was asked by the government to buy the Amsterdam Power Exchange because it was in financial difficulties

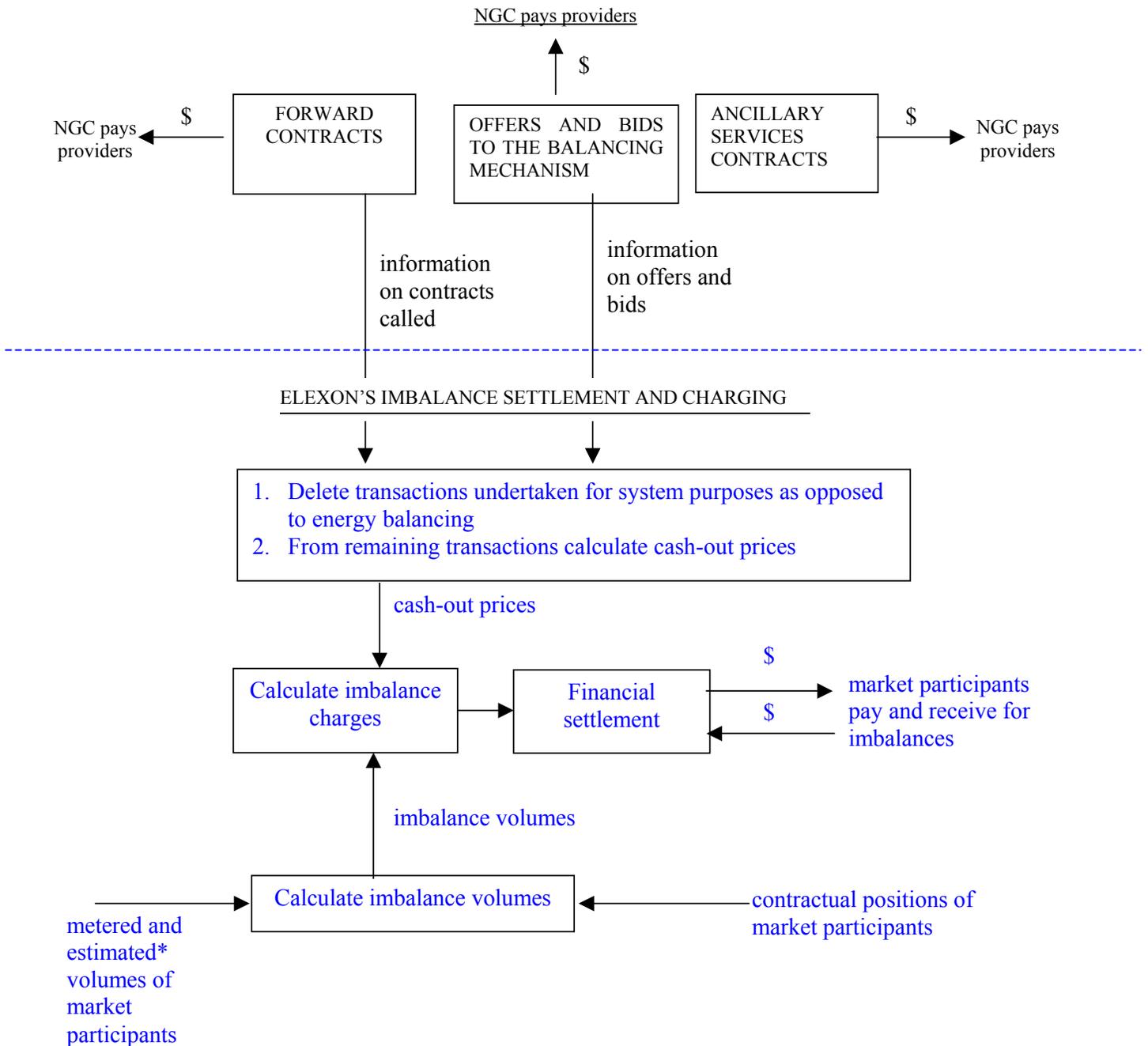
⁶ Regional Transmission Expansion Plan Approved, PJM Press Release, June 7, 2001, together with an analysis by PJM.

⁷ The powerflow through the system in England & Wales in 2001 was 304TWh and the maximum demand was 51,000MW, compared with 265TWh and 54,000MW for the PJM. England & Wales is 151,000sq km and PJM is 124,000sq km.

Exhibit 2

THE RELATIONSHIP BETWEEN NGC'S PROCUREMENT MARKETS AND THE SETTLEMENT AND CHARGING FOR IMBALANCES

NGC'S PROCUREMENT MARKET



* estimated for customers who do not have interval meters

- three of the regulatory frameworks - in England & Wales, Norway and Finland - incentivise the reduction of congestion. Thus NGC has a PBR scheme which incentivised it during the period 1994-96 to spend about \$95m on minor infrastructure capital and to improve its maintenance procedures. The result was to increase the capacity of its network by 22%, which resulted in congestion costs reducing from \$385m in 1993 to circa \$30m in 1998. Also in that period NGC reduced the costs of ancillary services from \$360m to about \$250m⁸ (see Annex 1)
- they all provide a point access services which provides access to the market in the member states of the European Union plus Norway, but which does not include a hedging component for cross zonal constraints which in most cases provides firm access to a defined market. We suggest FERC might consider this approach because it is simpler and more flexible than US point to point or network service, but we do not develop the issue further in this paper which focuses on institutional arrangements

The lessons that might be learnt from the European arrangements are the importance of a strong network that is generally owned by a stand alone transco which is subject to a regulatory framework that usually facilitates development. Except for TenneT, none operate day-ahead markets, and while most operate an imbalance arrangement they are not intended to be markets. None consider that LMP is the appropriate basis for a market. Finally the structure in England & Wales shows both the importance of incentivising the efficient use of existing assets, and that the balancing arrangements can be split from system operation and operating forward markets. **Annex 1 shows that the effect of these arrangements is to clearly separate the responsibilities for 1) transmission asset ownership and system operation, 2) the settlement and charging for imbalances, and 3) forward energy markets⁹:-**

- **transmission asset ownership and system operation – i.e. the transport of electricity – is undertaken by NGC**

⁸ We note with interest the following observation made in “Comments of PJM Interconnection L.L.C. on Allocation of RTO characteristics and functions between organisations within an RTO region”, PJM Electricity Market Design and Structure, Docket No. RM01-12-000, March 12, 2002; United States of America before the Federal Energy Regulatory Commission.:

“Assuming a baseline level of congestion (produced by prior ITC operations) and then rewarding the ITC to reduce the congestion it previously produced is a regulatory morass fraught with difficult monitoring and regulatory issues. While regulatory mechanisms have been used like this in the United Kingdom, there are no LMP-based markets in the U.K. to provide pricing mechanisms and incentives to relieve congestion. The U.K. regulator had no choice in the absence of LMP markets but to use old-fashioned regulatory mechanisms to reduce congestion.”

To ask an obvious question, would customers prefer to pay \$30m in England & Wales with “old fashioned regulatory mechanisms” or \$271m in the PJM with LMP. Although the PBR scheme may be simple and crude, it is not as PJM claims “a regulatory morass fraught with difficult monitoring and regulatory issues”. Basically Ofgem sets a relatively short term PBR scheme and relies on NGC to reveal the scope for savings by beating the target. Then for the next period the target is ratcheted down.

⁹ Note that when the Pool functioned as the basis of the trading arrangements, although NGC undertook various services on behalf of the Pool according to rules prescribed in the Pooling & Settlement Agreement, NGC did not operate the Pool as a market operator – it acted as an agent to the signatories to the Pooling & Settlement Agreement, and they prescribed the rules.

- **imbalances are settled by ELEXON according to the rules of the Balancing and Settlement Code, which are determined by the Balancing and Settlement Panel subject to authorisation by Ofgem**
- **running forward energy markets, which can be undertaken by anyone**

3. ORGANISATIONAL ARRANGEMENTS AND MARKET DESIGN IN ARGENTINA, AUSTRALIA, AND NEW ZEALAND

Argentina, Australia, and New Zealand provide other models of institutional frameworks, see exhibit 3.

Exhibit 3 The institutional framework in Argentina, Australia, and New Zealand

	Owner	Transmission network		System operation	Centralised dispatch or not	Imbalance arrangement	Short term market	Congestion measurement
		Ownership	Development		yes			
Argentina	Transener	private	system users + BOM tender	CAMMESA	yes	CAMMESA	none	LMP
Australia - Victoria	PowerNet	private	VenCorp + BOM tender	NEMMCO	yes	NEMMCO	Sydney Futures & Options	5 zones
- NSW	Transgrid	NSW government	Transgrid	NEMMCO	yes	NEMMCO		
New Zealand	Transpower	government	System users	Transpower	yes	M-Co	none	LMP

They are similar in that they all run centralised dispatch systems, and two run LMP while the framework in Argentina is broadly similar to FERC’s proposed Standard Design except that there is no day-ahead market. The other two depart from FERC’s proposals in significant ways, notably:-

- in Australia the system operator has no responsibility for running a day-ahead energy market nor for network planning. In New South Wales there is a transco, and in Victoria an independent system planner
- in New Zealand Transpower is a “transco” but it is not responsible for developing the network, nor for operating the real time market in the sense that it neither determines the market rules, nor does it settle the real time market. There is no short term forward energy market

The lessons that might be learnt from these arrangements are that none of the system operators run day-ahead markets, and although New Zealand has LMP to price transmission, it repeats the experience of England & Wales in splitting the balance market from system operation.

4. THE SHORTCOMINGS OF THE ISO STRUCTURE

The concept of the ISO was devised to address the problems associated with both the balkanised ownership of transmission and ownership by vertically integrated utilities that would be able to discriminate in favour of their own generation and consequently distort a market. Although it is the best approach when transmission ownership is balkanised and some is owned as part of integrated companies, we do not consider that this institutional structure is optimal because it fragments the provision of a transmission service into:-

- transmission owners providing a “wires service” of maintaining poles and wires in return for collecting a rental for the assets and perhaps on instruction from the ISO trying to build more facilities – they play a passive role
- the ISO resolving congestion, organising the provision of ancillary services as per Order 888, and computing losses charges

Neither the transmission owners nor the ISO provide a “joined up” transmission service of transporting power from entry to exit points – they each provide parts of the service, which they do on a cost-pass-through basis. A common feature of all of the ISOs is that they are de facto not-for-profit companies which neither have a significant balance sheet nor are they guaranteed, and consequently they are cost-pass-through organisations that (unlike transcos) cannot bear either the risk of significant PBR schemes or the type of transmission access contracts that we describe in the concluding section. Their clear responsibility is to keep the lights on, a task for which they have no financial constraints. The consequences of this institutional framework are that:-

- there is no clear incentive on any party to either *manage* congestion in the active sense of the word of controlling and reducing it, nor to procure ancillary services efficiently. Thus we see that the costs of congestion in the PJM increased from <\$100m in 1999 to \$271m in 2001 compared with about \$30m in England & Wales¹⁰
- there is generally no clear responsibility for planning the economic development of the network, and no direct incentive to invest because the parties that bear the cost of congestion may not have the means to mitigate it¹¹

In a submission to FERC Dr. Larry Ruff commented¹² “Who should plan and implement transmission expansions is a complex and contentious issue for which there is no perfect answer.

¹⁰The Market Surveillance Committee of the California ISO observed in 1999 “that the ISO does not bear the final cost of the reserves that it acquires. These are passed on to the users of the system. However, as a fledgling institution, the ISO has a very strong incentive to avoid serious reliability problems. The thorny problem of providing operators the incentive to both minimise costs and ensure adequate reliability is a long-standing one in the electricity industry”.

¹¹ We comment below on proposals being developed in New York.

¹²Allocating RTO Functions, Submission of Larry E. Ruff, PhD, Electricity Market Design and Structure, docket No. RM01-12-00, et al, March 2002.

The RTO, ITCs/Transcos, market participants and even sponsors of potential “merchant” transmission projects will all play a role in identifying transmission needs and analyzing alternative solutions. Final decisions will almost always be made in some complex stakeholder/regulatory process.” *We entirely agree with Dr. Ruff that there is no perfect answer to the planning of transmission expansion which is complex; but it is particularly complex in a fragmented structure - the process is a mess.*

5. CLARIFYING SOME ISSUES IN THE “SLICING AND DICING” DEBATE

We think that some of the arguments that have been advanced in the “slicing and dicing” debate show a lack of understanding of market design in other countries in making categorical assertions about design features that it is claimed must be wrong¹³, when those features function perfectly well elsewhere. They are also based on misconceptions that wrongly conflate the functions of system operator with that of operating an imbalance arrangement and a short term forward energy market, and confusion of the concept of LMP. It is thus helpful to clarify some fundamental concepts.

Unbundling functions

For a start the basic role of a system operator is to ensure that a transmission network operates reliably within security constraints by 1) balancing demand and supply on an instantaneous basis by redispatching plant and load from several categories of reserves; 2) resolving constraints by redispatching generating plant and load (a process which is linked to the first); and 3) providing voltage support. Traditionally within an integrated utility or in a centrally despatched tight power pool the system operator’s responsibility was extended to include an objective of minimising very short term operational costs, which was achieved using an optimising algorithm to minimise marginal plant operating costs taking account of plant dynamics, losses and subject to security constraints. *In such an arrangement there is no need for the system operator to be concerned with LMPs per se (as was the case in the “old” PJM).*

The centrally dispatched markets, like the former Pool of England & Wales and the “new” PJM, are the direct descendents of the traditional approach where the marginal plant operating costs become offer and bid prices and the system operator runs additional “procurement markets” to buy ancillary services. All the offers and bids are put into an optimising algorithm which dispatches to minimise

¹³ For example Mr. John Chandley and Professor William Hogan claim that “the problems that arise when we do anything else [different from their proposals] are apparent in various experiments where putative simplifications produced predictable problems”, see “Independent Transmission Companies in a Regional Transmission Organisation,” John D. Chandley and William W. Hogan, LECG, LLC and Centre for Business Government, John F. Kennedy School of Government, Harvard University, Revised January 8, 2002, www.whogan.com.

the total prices of the system. *Again, to fulfil the role of system operator it is not necessary to know LMPs (although they are implicit in the actions the system operator takes).*

As a second – and entirely separate – stage nodal locational marginal prices can be derived from the system dispatch and used for two further purposes:-

- to *measure* the costs of congestion at different points in the network. The measure can be used:-
 - * as an indicator of the short run availability of the network;
 - * perhaps to measure the performance of the system operator in dispatching the system;
 - * as an indicator of the locational value of the network;
 - * as an indicator of the need to build more transmission facilities
- for determining prices to settle imbalances in schedules

Neither of these two purposes is directly related to the system operator’s basic role, while the second has nothing at all to do with system operation. *Furthermore neither of these functions need to be undertaken by the system operator. The mere fact that these processes use information resulting from system operation does not in this day of sophisticated information technology require that the system operator is also the operator of the imbalance arrangement. Thus in England & Wales although NGC accepts bids and offers it most definitely is not operator¹⁴ of the Balancing Mechanism which is used to settle imbalances. It neither provides the governance structure for determining the Balancing Mechanism rules, nor does it run the administration of settling imbalances.* (Conversely, in Italy the market operator will accept the offers and bids which the system operator will use, while the system operator will settle imbalances).

In contrast to the centralised market model favoured by FERC, all the markets in western Europe are based on generators creating an (approximate) merit order by trading between themselves, providing the system operator with their expected generation schedule, and then to dispatching themselves. This leaves the system operator to meet security requirements by buying energy balancing and adjustments to meet constraints in markets where both generation and load make offers and bids to increment and decrement the level of output, and by buying other ancillary services such as

¹⁴ A *market operator* is an organization that through an appropriate governance structure sets the rules for trading; provides a forum for trading and if an exchange based market acts as counter-party; settles trades; and has arrangements for handling credit risk. Operating a market involves undertaking most of these functions, but most critically providing the governance structure for setting the rules and settling the transactions.

frequency response in short term procurement markets or through forward contracts or on a regulated basis where there is little or no prospect of workable competition¹⁵.

In view of the foregoing analysis and of the ways in which the institutional arrangements have been structured in Europe, we do not agree with the assertion that FERC makes in its Working Paper that:-

“Under LMP, the imbalance and transmission markets must operate together. Thus it is more efficient to have one entity perform the two functions identified by NERC in its new Functional Model as the Balancing Authority and the Transmission Service Provider...The transmission service provider must operate a day ahead market...”¹⁶

The various activities can be organizationally unbundled.

Putting LMP into perspective

Although LMP is a reasonably accurate method for measuring and signalling the price of congestion but, as we have argued, the calculation of LMPs is not necessary for *relieving* congestion nor does the measurement of such prices necessarily lead to *managing* congestion. Furthermore, although they can provide appropriate signals for locating generation they do not (except in restrictive conditions) provide correct signals for merchant transmission expansion.

Efficient investments maximise welfare. Assuming inelastic demand, this equates to minimising costs, *not* prices. We show in Annex 3 that for a simple two node network, incentivising investment by exposing “pure” merchant developers (i.e. those without an interest in the energy market to LMPs does *not* generally result in an efficient system regardless of whether LMP exposure is hedged by TCCs because the incentive to invest in a mature transmissions system will either to

¹⁵ Reactive power is generally either provided “free” as a code requirement or bought on a regulated tariff basis. In England & Wales, however, there is a reactive power market based on tenders that provides almost half of the requirement.

¹⁶ FERC also observes (p12 of the Working Paper) that “While a day-ahead market is not strictly necessary for resolving imbalances, experience has shown that the combination of a day-ahead market and real-time market enhances system reliability and efficiency compared to operating only a real-time market...Markets that have operated with both a real-time and day-ahead market are more efficient than those with only a real-time market.”

We do not believe that there is enough experience of markets that (in other respects) are identical operating with and without a day ahead market to arrive at the conclusion which FERC draws. Mr. Jim Gallagher, who played a major role in restructuring the electricity industry in Victoria and in the development of the Australian National Electricity Market, commented (Personal e-mail 04/10/02):-

“I think a day ahead market of some form has a lot to offer, particularly to enhance demand side participation. However, I think this can be provided through the normal financial markets on a voluntary basis - there is no need to tie it into the physical market. Furthermore I am not persuaded by the suggestion that the combination of a day ahead and real time market “enhances system reliability and efficiency compared to operating only a real-time market”. There is no evidence in the many years of Australian experience which suggests there has been any discernible problems in that respect, at least in terms of supply side involvement.”

result in any investment at all, or if it does it will not be optimal. Accordingly, large ('lumpy') investments in transmission infrastructure should be designed to minimise expected total *costs*, which is inherently a central planning activity that cannot sensibly be driven entirely by market *prices*. Prices do, however, approximate to efficient signals for a series of small, incremental investments, and thus LMPs could be used to incentivise investment at the margin. A further point to note is that how a merchant line is sized compared to a socially optimal line depends upon the character of the party which is promoting it. Ignoring the lumpiness of transmission investments, compared with the optimally sized investment, a merchant investor will tend to undersize lines compared with the socially optimal in order to maintain an adequate price differential because over-investment destroys the value of the investment, while an investment backed by generators in an export constrained zone (or customers in an import constrained zone) may oversize lines.

Even if the LMP/TCC signals were reasonably correct – which they are unlikely to be for major expansions - the proposals under consideration in New York¹⁷ for linking quasi-long term TCCs to merchant investments appear to be complex and their effectiveness might be limited by a lack of demand side involvement where fully developed retail access is implemented¹⁸, and also by the difficulties in forming coalitions when they are necessary to give most of the potential benefits. And although there are currently no provisions supporting regulated expansion, if the merchant approach is seen to fail and regulated facilities are built, they would undermine the incentives and economics of merchant investments. This has already happened in Australia¹⁹, where the world's first merchant line was built. Namely work on a merchant interconnector commenced between New South Wales and South Australia, and then a regulated interconnector was announced that would benefit from guaranteed cost recovery and a lower cost of capital, and which would depress the price differential between the market areas.

LMP should be seen for what it is, and no more. Namely it is a way of providing short run locational pricing signals in a market with centralised dispatch. Conceptually it is the most accurate way and theoretically it maximises social welfare, but thus far there have thus far been no empirical

¹⁷ "TCC Awards For Transmission Expansions", Prepared for the NYISO Business Issues Committee, Susan L. Pope, LECG, March 20, 2002.

¹⁸ By fully "developed" we mean retail access that is implemented across a wide market area with uniform systems that allow for easy switching; with no provider of last resort offering regulated safe-haven rates; and pricing based on the build up of component costs (energy + wires + retailing) rather than on contrived shopping credits. Under these circumstances, apart from very large customers, there is unlikely to be a market party on the demand side with both a long term financial interest and the strength to bear the risk of long term investments. Small customers may have the interest, but do not have financial strength; retailers with a shifting customer base do not have the interest unless they can create a monopoly advantage in supply customers in an import constrained area.

¹⁹ Regulated and Merchant Transmission Investment – Lessons from Australia, Presentation to Harvard Electricity Policy Group, Philip Gall, Manager Regulatory Affairs, Transgrid, 23 January 2003.

analyses of the effectiveness of LMP signals compared with zonal pricing in influencing the short term behaviour of market participants, nor of the extent of loss of welfare from using zonal prices, nor of the consequences (if any) for the liquidity of contract markets by introducing additional basis risk using LMP. *In any case we consider it is generally more important to reduce congestion than to measure it at all nodes in a network.*

6. THE WAY FORWARD

In view of the importance of having a strong transmission system as the basis for efficient wholesale markets, we suggest FERC's priorities should be to:-

- incentivise the development of more transmission where it is appropriate to do so and in as market oriented manner as is possible, which we discuss in the following two sections
- incentivise the maximum use of the existing network to reduce the costs of congestion, which can be achieved by introducing effective PBR incentives and which we discuss in the third section

The case for the wide area transco

The first objective will only be achieved by separating transmission from generation and encouraging the evolution of dedicated transmission companies that wish to build a profitable business from transporting electricity (as opposed to being mere passive rentiers of poles and wires largely subordinate to RTOs) both by buying existing assets and by developing new assets so that they become wide area transcos. Rather than devise ever more elaborate stakeholder procedures and complex TCC auctions which we doubt will provide adequate incentives to build sufficient transmission facilities due to the scope for market failures, to get transmission developed requires dedicated transcos who (within an appropriate regulatory framework incentivising efficiency) "will go for it".

We appreciate that FERC has to start from the current position, and thus understand that the ISO structure has an important role to play in making the best of an unsuitable ownership structure. But we suggest that the Order which results from the Working Paper should encourage the development of wide area transcos. They would own assets and as system operator would control the system from say an hour ahead down to real time and to that end would handle congestion, losses, and ancillary services to the extent that market participants do not self provide. Whether or not the transco or some other organisation independent of market participants (e.g. an RTO) operates a real time imbalance market and a day-ahead energy market is an issue that can be dealt with separately. Note that in the Nordic market (which is the largest unified electricity market in the world) five

different transmission system operators provide imbalance services. They trade among themselves and so the effect is more or less an integrated arrangement, see Annex 1.

User oriented transmission expansion

We further suggest that there should an attempt to move in part from centralised transmission planning to a more “user oriented” approach that allows the users – generators, distribution networks, and directly connected consumers of the network – more choice and influence, which is market driven, and which incorporates incentives for both efficient operation and development. To this end we have developed a new approach which is based on the concept of “transmission access contracts”²⁰ between the user and the transco (and in some circumstances might be with other parties) which in return for a payment would define a level of access to the shared network coupled with a predefined level of compensation if that access is not provided. System users would be offered commercial choices to suit their commercial needs. Thus to illustrate a generator user might be offered:-

- the basic “vanilla” service which would be that a generator is constrained-off as and when necessary with no compensation, i.e. it takes the network as it is
- the “negotiated access choice” which would offer a generator a medium to long term “transmission access contract” that would incorporate the degree of firmness the generator desires with compensation on a mutually acceptable basis. For any level of capacity there would be two dimensions to firmness, condition and the basis of compensation. The condition element would give options as to whether the chosen compensation amount was to be payable at all times or only for (say) 80% or any other proportion of the year, and how the times should be decided e.g. agreed yearly in advance or related to prices in a particular market, or related to the system demand, or related to hydro conditions, etc. The level of compensation could be a fixed amount per MWh, or something related to a market price for electricity, or related to a market price for electricity together with a figure nominated in advance. There could be caps and collars for any of these amounts on the total amount of compensation in a year

Different generators will have different needs. One may be located in a strong part of the network and currently may not be likely to be constrained-off and so may not need more than a vanilla access contract until someone builds another generator near by. Another small generator with a modest balance sheet might require a 20 year access right for (say) 8000 hours including 750 hours during a predefined peak period of 1000 hours with sufficient compensation to enable it to secure a relatively high level of bank financing. In contrast a portfolio generator with an old plant that has a limited life might want a short term contract providing access when the system demand was above a certain

²⁰ The British regulator Ofgem has recently conceived of a crude version of our concept, see “Transmission Access and Losses Under NETA: Revised Proposals”, Ofgem, February 2002, www.ofgem.gov.uk.

level. Access for all demand either from individual very large customers or via a distribution network would be dealt with in the same way.

As well as providing the users *with the service they want* such contracts would provide the transco with incentives to maximise the use of its existing assets and to develop the network. Thus suppose a generator had a three year contract with prescribed terms of access and compensation. If the transco realised the conditions of access were going to be breached, then it would have choices between taking some action (e.g. buying redispatch, negotiating a load reduction contract with a large user, speeding up maintenance, increasing thermal limits, installing compensators or FACTS) or paying compensation. For longer term access it might build more facilities.

A new regulatory framework

We note, and welcome, FERC's intention to distance Market Monitoring from an RTO. We do not think it is appropriate for an institution such as an RTO which is providing services to market participants to fulfil a regulatory role. (Obviously no one would argue the reverse case that a Public Service Commission or FERC should provide market services). We suggest that FERC goes further and first ensures that the RTO has no say in the selection of people and is itself included in what is monitored, and second extends the scope of regulation. We suggest that the regulatory responsibilities relating to the operation of markets and of transcos or ITCs needs to be developed. Namely, to ensure that the transco is efficient it must be subject to an appropriate regulatory framework which might include:-

- a PBR scheme for its operations and maintenance costs
- should include a PBR scheme for system operation costs
- surveillance of the construction of any lines built on a regulated basis; surveillance to ensure that other parties wishing to build merchant facilities are not obstructed
- market monitoring and compliance
- determining market rules and resolving disputes
- ensuring that transcos/ITC/transmission owners provide a non-discriminatory service
- approving tariffs including arbitrating on transmission access contracts; setting PBR schemes for system operations

We envisage an overall framework of responsibilities as shown in exhibit 4.

Exhibit 4 Responsibilities of the transco, the RTO, and the Regulatory Agency for geographic areas where there is a transco

<u>Functions</u>	<u>Transco</u>	<u>TO</u>	<u>Market Company</u>	<u>Regulatory agency</u>
System operation	Provider of last resort for ancillary services; purchase balancing energy; undertake congestion management and provide data for calculation of LMPs	None in the transco area ²¹		Devise PBR scheme for system operation
Publish LMPs and settle imbalances for transco area	EITHER Publish LMPs for transco area and operate imbalance energy markets settlement for RTO area	OR Publish LMPs for RTO area and operate imbalance energy markets settlement for RTO area perhaps less transco area	OR Publish LMP and operate energy imbalance markets for appropriate areas	Authorise rules for imbalance market Monitor and take action over market power
Planning and expansion of transmission	Develop own network including that required to meet needs of the access contracts. But merchant developers should also be allowed to build	Assess overall requirements RTO has ultimate authority to build when there are impacts outside the transco footplate		Ensure that merchant facilities have a level playing field Arbitrate disputes about transmission access contracts Set network charges for regulated expansions
Intra- and inter-regional coordination	No duties	Responsible for intra- and inter-regional coordination		
Forward energy market	Possibly operate	Possibly operate	Possibly operate	Monitor and take action over market power

* * *

²¹ In geographic areas where there is no transco the RTO would be system operator and would plan the development of the network.

Where transmission ownership is balkanised the ISO/separate transmission owners structure may well be the best that one can do. But we think it is only by having an efficient transmission system that an effective wide area energy market can be enabled, and this will only be achieved by a transco that (via a regulated incentive scheme and/or contracts with its customers) has the incentives to provide an efficient market oriented transport businesses, which has incentives to operate the network efficiently and develop it and is user oriented as possible.

Annex 1 THE INSTITUTIONAL FRAMEWORK FOR TRANSMISSION, SYSTEM OPERATION, AND MARKETS IN MAJOR WESTERN EUROPEAN COUNTRIES

This annex first sketches the institutional arrangements in:-

Germany
Italy
France
Spain
The Netherlands

After these sketches there are more detailed descriptions of the most mature and genuinely competitive electricity markets in Europe, namely those in England & Wales and in the Nordic countries, which are by any metric the most successful markets in Europe:-

- although we would not claim that the E&W market is perfect, on a system with a maximum demand of 53GW it has provided a platform for the development of 25GW of plant under competitive market conditions over a period of 11 years plus an expansion of the interconnector with Scotland by 1.1GW; has seen the development of an effective competitive retail market for commercial and industrial customers, who have benefited from a reduction in prices of 40% in real terms since 1993²², and for residential customers:-

- * a report “European Energy Market Competition: What has it delivered?” prepared by Accenture²³ in March 2002 for the Financial Times observes that:-

“The UK can probably claim to be greatest success story of energy liberalisation in the world. It is the only European Union country that has successfully implemented all the policies and structural reforms called for in the European Union Directives on electricity and gas market liberalisation. As a result, the UK has seen among the greatest benefits from competition in terms of customer choice and price reductions. Retail electricity and gas switching rates – at close to 40% – are the highest of any market in the world, while prices for both domestic and industrial customers are among the most competitive in Europe.”

- * a recent report “Pipes and Wires” published by the National Audit Office (which is the UK equivalent of the General Accounting Office), states “Consumers of basic services delivered by pipes and wires have benefited from lower prices and more reliable services as a result of the way these services have been regulated” (www.nao.gov.uk)²⁴

²² See Table 3.3.1, Quarterly Energy Prices, Department of Trade and Industry. Strictly the reduction applies to industrial customers, but larger commercial customers with sites over 100kW will have enjoyed similar benefits. The start date of 1993 was chosen because that is the last year when British deep mined coal was subsidised by these customers.

²³ www.accenture.co.uk.

²⁴ Although not directly relevant to market issues we included this point to counter Dr. Ruff’s assertion that “the British political/legal system is far more tolerant than is the US system of powerful, lightly regulated and highly profitable monopolies”, see “ISO/Gridcos versus Transcos: What, Why and Who Cares?” – a presentation to FERC, February 19, 2002.

- the Nordic market is notable both for the simplicity of market design, and the pragmatism with which changes are made in an evolutionary manner with a minimum of legalism and attorneys, and noise. Judging by the turnover of 2000 billion kWh p.a.²⁵ in the contract market (which is about five times physical) the wholesale market is successfully liquid. Accenture comments that “Sweden and Finland²⁶ have also been leaders in energy market liberalisation, particularly in electricity, and customers in these markets now enjoy the cheapest power in Europe”

GERMANY, ITALY, FRANCE, SPAIN, THE NETHERLANDS

With the exception of Germany, the main west European countries have all adopted – or in the case of Italy, will adopt – a national transco model. The restructuring of the **German** electricity system is unusual among the main countries of western Europe in that transmission remains separated among four vertically integrated companies, all of which are privately owned and each of which remains a system operator with its own control area. The transmission network and system operation have been unbundled into “transmission system operators” and each either now operates or will shortly operate 15 minute imbalance markets with a single clearing price for discrepancies. Although there is a provision for “market splitting” in Germany as in the Nordic market (see below), the transmission network is so strong that Germany effectively operates as a single price area. There are two exchange based markets in Germany, the European Power Exchange based in Frankfurt and owned by the Frankfurt Stock Exchange, and the Leipzig Exchange owned by the City of Leipzig, the Lander of Saxony, and NordPool (see below), which run day-ahead spot markets. The exchanges are completing a merger. Germany is unique among countries in not having an industry regulator, although the Federal Economics Ministry has set up a task force to examine network access and the Federal Cartel Office has recently set up an additional unit for regulating the electricity industry.

In **Italy**, prior to restructuring, ENEL was a statutory corporation which owned about 90% of the generation capacity, nearly all of the high voltage network, and served 93% of all of the customers. The remaining generation, transmission, and distribution is provided by a number of municipals and several private companies. A decree in 1992 transformed ENEL into a company and enabled the government to privatise it, which was partly done in 1999 with the sale of 32% of the shareholding. In 1999 the high voltage transmission grid was transferred to a subsidiary of ENEL called Terna, which acted as a pure wires and poles company and, by a decree of 2000 system operation was transferred from ENEL to Gestore della Rete di Trasmissione Nazionale (GRTN), which is a

²⁵ This estimate is provided by SKM Energy, which is both a broker and the leading consultancy on market design in the Nordic countries.

²⁶ Accenture’s survey did not include Norway because it is not part of the European Union.

company owned by the government. A subsidiary of that company, Gestore del Mercato Elettrico S.p.A (GEM), is developing a spot market which can split the market into zones when there are constraints, but there will probably initially be a single national price. GME also runs a procurement market for reserves for GRTN, but GRTN settles imbalances in schedules. Currently, as the market is not functioning, the settlement prices are derived by formulae, but in future there may well be two prices based on clearing (i.e. marginal) prices of regulation-up and –down similar to the arrangement in Finland, see below.

The government has just announced that TERNA and GRTN will be combined and privatised, and the organisational location of Gestore del Mercato Elettrico S.p.A will be reviewed.

Restructuring in **France** is in its infancy. Electricité de France remains owned by the state and also remains a statutory corporation. It has been unbundled into three main business units for its electricity business within France, namely generation, distribution and supply, and transmission which is called Resaux de Transporte d'Electricite. The latter is system operator, owns the high voltage network and is responsible for developing it, and provides a balancing service that is currently based on tariffs. It is separately regulated from the distribution and supply business unit, and is subject to some legislation which affects only it. Although the transmission tariffs vary by voltage level the tariffs are uniform across France and include the costs of congestion. There is a day ahead spot market (which treats France as a single price zone) run by Powernext, which is a subsidiary of Euronext, the company that runs the merged French, Belgian, and Dutch stock markets.

The **Spanish** restructuring started with the advantage that Red Eléctrica, which owns the majority of the 220kV lines and all of the 400kV lines, was created as a separate transmission asset owner and system operator in 1985. The restructuring included removing the requirement that the government had to own the majority of the shares and had voting control, and now it is majority privately owned – electric utilities may jointly own up to 40% - and has a quotation on the Spanish stock market. Red Eléctrica manages congestion and also operates the two reserves procurement markets for secondary and tertiary operating reserves. It uses the marginal prices from purchasing reserves, plus a penalty to settle imbalances. Compania Operadora del Mercado Espanol de Electricidad (OMEL), which is owned by a diversity of private entities – and there is a limit of 40% to the participation of electric utilities – operates a day ahead market which is uniform across the country and also an intra-daily market which remains open until 2¼ hours before run time. Red Eléctrica is also in charge of

preparing (in consultation with other stakeholders) a plan for transmission expansion, and there is then a procedure for tendering build/own/maintain contracts for new transmission facilities, although the rules of the tendering have not been defined yet and effectively Red Eléctrica would undertake the expansion.

The **Netherlands** also commenced its restructuring with an organisation that was a separate and unified transmission asset owner that owned about three quarters of the 220kV and 380kV facilities in the country, and was system operator for the whole country. In 1998 TenneT was created and the government bought it in 2001 with the intention that it would be privatised in due course. But due to the perceptions of the debacle in California and the collapse of Enron, Dutch politicians have put sale on hold. TenneT is responsible for:-

- owning most – and possibly in the future, all - of the high voltage network
- developing the network efficiently to ensure that there is adequate capacity
- operating the interconnectors with Germany and Belgium
- ensuring the system is operated reliably and securely
- providing a balancing arrangement to settle imbalances. Scheduling coordinators are supposed to balance their schedules. Imbalances are settled with one price for shorts and another for longs based on the marginal prices of buying regulation-up and –down. There is a provision for adding a penalty to the prices if needed to encourage balanced schedules
- ensuring generation security of supply

TenneT charges for its network and system (including congestion) through a nationally uniform tariff, which means that the Netherlands is a single price area for energy transactions.

The Amsterdam Power Exchange was sponsored by energy companies and incorporated in 1998 to run a spot market and other products, but the market has not been very liquid, and consequently the Exchange was losing money and at risk of bankruptcy. The government suggested to TenneT that to help the market it might buy the Exchange, which it did in May 2001. It is run as an arms length subsidiary and while there is an exchange of data, there are no functional links between the Exchange and TenneT as system operator.

ENGLAND & WALES

The restructuring of the electricity supply industry in England & Wales on 1 April 1990 involved changing the twelve government owned local distribution undertakings from statutory corporations into companies that were called Regional Electricity Companies and unbundling their wires distribution business from their retailing, and splitting up the state owned Central Electricity Generating Board, which was a statutory corporation that owned virtually all of the generation for the public supply system in England & Wales. The generating Board was split into:-

- three generation companies with between 10 and 28GW of plant (there are now 10 generating companies owning plant with a capacity of between 2-9GW and a further 6 companies with a capacity of 750MW – 2000MW)
- the National Grid Company (NGC) is both transmission asset owner and system operator. NGC was owned by the Regional Electricity Companies, but it was floated on the London Stock market in December 1995 and subsequently quoted on the New York Stock Exchange

Also the Pool of England & Wales was created as a day ahead spot market, and it operated until the end of March 2001, when it was superseded by the “New Electricity Trading Arrangements” (NETA).

NGC

NGC owns all of the 400kV and 275kV high voltage lines in England & Wales, shares ownership of a 2000MW DC interconnector to France and owns the English part of the AC interconnecting lines with Scotland which will shortly have a capacity of 2200MW. NGC has statutory duties defined in primary legislation:-

- to develop and maintain an efficient, co-ordinated and economical system of electricity transmission
- to facilitate competition in the supply and generation of electricity

It has a transmission licence which provides the regulatory framework and defines what NGC must do, how it must do certain things (e.g. offer non-discriminatory terms), and what it may not do. The regulator (Ofgem) monitors compliance with the conditions and has the power to enforce them. The obligations on NGC now include requirements:-

- to offer terms to any generator or supplier who wishes to connect to and to use its system. In setting the terms NGC shall not "restrict, distort or prevent competition in the transmission, distribution or generation of electricity", and the terms have to be non-discriminatory
- to purchase balancing services (which include ancillary services) or otherwise acquire ancillary services from the most economical sources available

- to have in force a Balancing and Settlement Code, see below

NGC currently charges the costs it incurs in three parts²⁷:-

- connection charges, which recover the specific capital and operations and maintenance costs of equipment required to connect each user (viz generator, distributor, and directly connected customer) to the shared network, i.e. the directly assigned costs
- the transmission network use of system (TNUoS) charge, which is designed to recover the capital and operations and maintenance costs of the shared network. The charge is differentiated locationally using a pseudo marginal cost technique called Investment Cost Related Pricing which provides strong locational signals in zones to both generators and loads. At locations where an increase in generation would lead to an increase in power flows, charges for generation are relatively high and for load are low; conversely where an increase in generation would lead to a reduction in power flows on the system; the TNUoS charge for generation can be negative. Overall generators pay for 27% of the costs of the shared network and consuming users 73%, an arrangement intended to ensure that generators would receive a locational signal that reflected where it would be more and less economic to locate from a system perspective
- ancillary services and costs of congestion were initially charged through the Pool uplift, and from 1994-95 to 1997/98 NGC was incentivised to reduce these costs. From 1997/98 to the introduction of NETA these costs were recovered by NGC via Transmission Services Use of System Charges and NGC continued to be incentivised to reduce them. Since NETA, the costs incurred by NGC in the Balancing Mechanism (which includes ancillary services and congestion) are recovered through the Balancing Services Use of System Charge

NGC did not initially take responsibility for managing costs of ancillary services and congestion, and they increased rapidly to \$530m (1997 prices) in 1993 (largely due to an increase in constraint costs), when they attracted the concern of both large customers and the regulator. Also losses steadily increased from 4.3TWh in 1990 to 5.6TWh in 1995. Over a period of years a scheme evolved which put ancillary services, constraint costs and losses into a “*Transmission Services Business*” which was regulated with a PBR scheme. The final scheme, which was introduced 1 April 2000 and ran for one year, set a target for the transport costs of \$280m, with NGC benefiting by 50% of any reduction enabling it to earn up to a maximum of \$30m, and bearing 50% of any cost overrun down to a maximum limit of \$30m.

The PBR scheme provided NGC with a strong incentive to increase the capacity of the network where that was possible through minor capex (improved monitoring, re-conductoring, installing quadrature boosters) measures, improved maintenance scheduling based on condition monitoring, and accelerated maintenance. During the period 1994/95 - 1996/97 NGC spent about \$85m of

²⁷ Losses, which are charged 45% to generators and 55% to consumers through an adjustment to their metered volumes of power supplied or consumed, are provided for outside the remit of NGC.

infrastructure capital expenditure (of which about \$42m was spent on schemes above the planning standard) which resulted in increasing the capacity of the network by 22%. According to Ofgem the operational transport costs reduced significantly as the following table shows:-

<u>Components of operational transport costs (1997 prices, £ = 1.4\$)</u>								
	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01
	(\$m)	(\$m)	(\$m)	(\$m)	(\$m)	(\$m)	(\$m)	(\$m)
response and reserve	210	180.8	162.8	229.3	219.9	210.7		
high voltage constraints	204.9	155.3	77.0	82.6	33.7	28.3		
low voltage constraints	98.4	70.8	0	0	0	0		
reactive, black start and other costs	<u>150.1</u>	<u>135.2</u>	<u>152.2</u>	<u>104.4</u>	<u>122.2</u>	<u>102.6</u>		
total congestion and ancillary services losses	745.8	594.3	324.8	416.4	375.9	341.6	281.4	279.2
				189.8	174.9	175.4		

Sources: Offer 2nd Consultation Document March 1996, Ofgem Initial Thoughts Document March 2003.

The effect of this scheme was to clearly make NGC a transport business, not merely either the rentier of poles and wires nor merely a system operator.

Since restructuring NGC has undertaken a significant capital programme as the following table shows (2001 prices: £ = 1.4\$):-

<u>NGC's capital expenditure (2001 prices, £ = 1.4\$)</u>											
	90/91	91/92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	Total
	(\$m)	(\$m)	(\$m)	(\$m)	(\$m)	(\$m)	(\$m)	(\$m)	(\$m)	forecast (\$m)	(\$m)
load related	262	342	434	321	258	179	171	158	196	158	2479
non-load related	<u>217</u>	<u>277</u>	<u>277</u>	<u>101</u>	<u>95</u>	<u>126</u>	<u>127</u>	<u>221</u>	<u>119</u>	<u>241</u>	<u>1801</u>
Total	479	619	711	422	353	305	298	379	315	399	4280

Sources: Offer 2nd Consultation Document March 1996, Ofgem Initial Thoughts Document March 2003.

According to Ofgem about a quarter of future load related capital expenditure is for connections. If this proportion applied in the past, then NGC's expenditure averaged \$320m p.a. over the 1990s on the shared network.

NETA and the imbalance settlement and charging arrangements

The core of NETA is the imbalance settlement and charging arrangements. A primary aim of NETA is to avoid a system marginal price (“SMP”) or uniform price auction such as the Pool had and PJM has, which Ofgem, the British regulator, believed facilitated the exercise of market power. Instead the aim is to encourage – if not effectively force – market participants to trade bilaterally in a bid-ask manner in a nationally uniform²⁸ energy market which should be similar to a “normal” commodity market. Market participants submit their final schedules at “gate closure”, which is currently 3½ hours before each ½ hour settlement period but will be reduced to 1 hour on 2 July 2002. To settle differences, while encouraging parties to balance, there are two settlement “cash-out prices”; a high price if a party is short and has to buy and a low price if a party is long and has to spill power. *The settlement is purposefully intended not to be a real time market, and its prices bear little or no direct relationship to the marginal costs of the system.*

NGC as system operator runs two procurement markets to buy the services it needs to balance the system, namely:-

- ancillary services such as frequency response and reactive power
- a Balancing Mechanism where generators and loads make offers to increment and bids to decrement after gate closure

In addition NGC also forward trades energy to balance the system and resolve constraints.

NGC pays for the costs of these services, and (similar to the Transmission System Services incentive scheme) NGC has a PBR scheme to minimise these costs. The scheme for 2002/03 is as follows:-

incentive scheme target	\$650
upside sharing factor	60%
downside sharing factor	50%
cap	\$85m
collar	\$-65m

The imbalance settlement process is undertaken according to the rules in the Balancing and Settlement Code. The initial rules in the Code were determined by Ofgem, and changes to the Code are recommended by the Balancing and Settlement Panel and approved by Ofgem. The Panel is comprised of a chair appointed by Ofgem, and (s)he in turn can appoint a further two independent panel members; two members can be appointed by the National Electricity Consumers Council; one

²⁸ Ofgem had hoped to introduce geographical differentiation of constraint costs through a complex arrangement of auctioning transmission access rights, but the concept was impractical and has been dropped.

member is appointed by NGC; and up to five members can be appointed by market participants. The Code states that the administration and implementation of the Code including the settlement of the imbalances, shall be undertaken by the Balancing and Settlement Code Company, a role that is currently performed by a company called ELEXON Limited. ELEXON provides the administrative support for the Panel and it procures, manages, and operates contracts and services which enable the balancing and imbalance settlement of the wholesale electricity market (and of the retail market). ELEXON is a not-for-profit company, with a board consisting of a chair who is the Chair of the Panel, two further Panel Members nominated by the Panel and two other independent members nominated by the Panel Chair. ELEXON is a wholly owned subsidiary of NGC, but NGC has no control over the Board and does not have any financial links with ELEXON nor responsibilities for it. *It was created as a subsidiary of NGC for regulatory convenience²⁹, not for any functional reason, and could in principle be entirely separate from NGC.*

The calculation of the two settlement prices for each half-hour is undertaken by ELEXON based on 1) the forward contracts for energy and reserve that NGC has bought and called, and on 2) the prices of the offers and bids which NGC has accepted in the Balancing Mechanism. In outline ELEXON for each half hour removes the contracts called and the offers and bids which NGC has accepted for constraint management, leaving those which it has called and accepted for energy balancing purposes, and from these it calculates the imbalance cash-out prices. It also calculates the imbalance position of each market participant from their contractual position and from the metered volumes injected and taken from the system. Finally it prices the imbalance volumes at the appropriate cash-out price. The relationship between NGC's procurement markets and the settlement and charging for imbalances is shown in exhibit 2.

Although in the early days of the development of NETA Ofgem proposed sponsoring a day ahead exchange market, it made a conscious decision to withdraw from this responsibility and to let the market provide. Four companies proposed to develop exchange traded markets, and two have succeeded. UKPX (which is a subsidiary of the OM Group which runs the Swedish options exchange and is involved in NordPool, see below) handles most of the day ahead ½ hour trades, which are traded to ½ hour before gate closure while the US company Automated Power Exchange offers a range of short term products. In addition several brokers offer short and long term products.

²⁹ The primary electricity legislation provides for four types of licensed activity in the electricity supply industry – generation, transmission, distribution, and retailing. There is no provision for licensing a company that provides an imbalance settlement service, and so a condition requiring this provision of the service was folded into NGC's licence.

The effect of these arrangements is to clearly separate the responsibilities for 1) transmission asset ownership and system operation, 2) the settlement and charging for imbalances, and 3) forward energy markets³⁰:-

- **transmission asset ownership and system operation – i.e. the transport of electricity – is undertaken by NGC**
- **imbalances are settled by ELEXON according to the rules of the Balancing and Settlement Code, which are determined by the Balancing and Settlement Panel subject to authorisation by Ofgem**
- **running forward energy markets, which can be undertaken by anyone**

THE NORDIC MARKET

The Nordic Market covers Norway (which was the first of the countries to deregulate and set the model for the others), Sweden, Finland, and Denmark. The first three countries and Eastern Denmark are AC interconnected, while Western Denmark is synchronised with the west/central continental European system and DC connected with Norway. The population and production in the Nordic market is as follows:-

	population (million)	production (2000) (TWh p.a.)
Denmark	5.3	34
Finland	5.2	67
Norway	4.5	143
Sweden	<u>8.9</u>	<u>142</u>
	23.9	386

The key features that enable the market to function as one are that:-

- there is free trade in electricity between the countries
- there is no pancaking of transmission charges – access at a point of any country’s network provides access to the whole system with no “border” charges, which is the so called “point access system”. The system is simple and provides no congestion hedging rights as do US style point to point or network service
- the networks between Norway and Sweden are strongly interconnected, between Finland and Sweden reasonably interconnected, while Eastern Denmark is strongly interconnected with Sweden, and western Denmark is reasonably interconnected with Norway and Sweden

³⁰ Note that when the Pool functioned as the basis of the trading arrangements, although NGC undertook various services on behalf of the Pool according to rules prescribed in the Pooling & Settlement Agreement, NGC did not operate the Pool as a market operator – it acted as an agent to the signatories to the Pooling & Settlement Agreement, and they prescribed the rules.

- NordPool has a de facto monopoly of providing a non-mandatory spot market across the market area
- there is no centralised dispatch – generators and loads self-dispatch
- there are broadly similar organisational responsibilities for the transmission system operators, who are asset owners with responsibilities for developing their national networks, for system operation, and each operates its own regulation or balancing market. The system operators trade among themselves, and so effectively there is a fairly integrated imbalance arrangements
- the long tradition of cooperation between the countries

The following section outlines how NordPool functions, and the succeeding sections look briefly at the organisational arrangements in Norway and Finland which are representative of the arrangements in all of the countries.

NORDPOOL

In 1971 the Norwegian government asked the electric industry to find a way of coordinating the use of hydro reserves (the system is 99% hydro), and the outcome was an energy "pool", which was run as a generators' cooperative and aimed to optimise the use of hydro resources in the reservoirs. In 1991, when the Norwegian industry was restructured to introduce competition and to provide access to the wires for all generators and customers, the pool was restructured into a company Statnett Marked which was a subsidiary of the transmission company Statnett. The company provided both a day ahead exchange-based spot market and ran the regulation (i.e. balancing) market, and then developed an exchange based market in physical forwards contracts. With the unification of the markets between Norway and Sweden on 1 January 1996, the regulation market was transferred to Statnett, and the other markets were transferred to NordPool, which is a company owned jointly by Statnett and Svenska Kraftnät, the Swedish grid company³¹. NordPool uses the Swedish Option Exchange Company (OM) as facilities manager and it provides the trading system.

Within the Nordic area NordPool has a de facto monopoly on running a non-mandatory day ahead hourly spot market called ELSLOT. The Nordic area is currently divided into 6 plus price zones within which the price of electricity is uniform, namely:-

- Norway is generally two price zones, but may be more
- Sweden is a single price zone
- Finland is a single price zone

³¹ Currently there are proposals to split NordPool into two companies, one running the spot market (see below) and the other running other markets. The ownership of the first company would remain as it is, but that of the second would be open to new investors.

- Western Denmark is a single price zone
- Eastern Denmark is a single price zone

Within each zone the costs of intrazonal congestion are socialised and incorporated into a transmission charge. When there are constraints between the zones the markets “split” and different prices are derived based on the bids and offers into each zone, which is explained in the following section.

Day ahead market bidding

Each day by 12.00 hours participants put in offers and bids for each hour bidding in the quantities which they will buy or sell at different prices. Participants with generators or consumption in different constraint regions of the market put in separate bids for the different regions.

NordPool balances supply and demand by hour to compute the market clearing price, and the resulting volumes that each party would buy and sell during each period to give a "provisional system price" (P_S) assuming there are no constraints on the system. (This price – called the “system price” – is used as the reference price for derivative contracts). Constraints are assessed based on the contracted power flows including the provisional buy/sell volumes computed from the unconstrained bid process. Then:-

- if there are no constraints P_S becomes the market price for the whole system and NordPool can compute the MW buy/sell contract for each period for each bidder
- if there are constraints, then NordPool has to compute separate prices for each price area by balancing the bids within each area which is called “market splitting”. A generator with supply contracts in different areas that are out of balance with its generation within an area is assumed to sell the power due to be transferred across the constraint to the sub-pool where it generates at the sub-pool price (P_G), and then to buy it from the other sub-pool at its pool price (P_C) for delivery to the customer. The power flow across a constraint multiplied by the difference in prices between two zones creates a congestion rental which is credited to a transmission system operator

The effect of this arrangement is that no party has the right to flow power across a constraint. If a party wishes to hedge the basis risk then it can buy contracts for differences from NordPool, which offers contracts for differences between an area price and the system price.

NordPool also operates a futures market which trades week strips up to about 8 weeks out, then strips of 4 week blocks to the end of the next season, then seasonal strips. The strips are financial swaps (viz two-way contracts for differences) referenced against the spot market system price. NordPool also has a forward financial contract in seasonal strips which run from the next season to

three years out, and it offers options and contracts for differences between the system price and the regional prices.

In 2001 NordPool traded 112TWh physical through the spot market, traded 910TWh of futures contracts, and acted as clearer for 2769TWh of over-the-counter contracts³².

NORWAY

Background to restructuring the electricity supply industry

The 1990 Electricity Act liberalised access to all transmission and distribution networks by all customers and generators, and gave all customers the right to choose their power retailer. The Act also introduced a new regulatory framework empowering the Norwegian Water and Energy Authority in conjunction with the Price Directorate to regulate the industry. At the end of 1991 Statkraftverkene, the state power and transmission undertaking was dissolved, and its production facilities were vested with Statkraft and its transmission assets were vested with Statnett, a new company owned by the government. Statnett owns about three quarters of the transmission grid, but in order to facilitate the efficient use of the whole grid, it has the legal right to lease those parts of the grid that it does not own and it operates and prices the whole system as an integrated entity. Note that any market participant is entitled to develop and own transmission, and to achieve development can seek powers of eminent domain. Users (i.e. generators, distribution networks, and large end-use customers) generally build and finance their own connections to Statnett.

The organisation and responsibilities of Statnett

Statnett's transmission responsibilities are:-

- to provide transport services on the main transmission grid
- to develop the network within Norway to connect customers and to accept and to provide supply
- to operate the whole network including the international tie lines to the national borders
- to control the system to maintain an acceptable level of reliable supply to which end it procures ancillary services and operates a regulation (i.e. balance market), see below

³² NordPool ASA, Annual Report 2001.

Statnett's transmission charges and regulation

There are four different elements to Statnett's charges:-

- a losses charge that is based on a forecast of marginal losses for each grid supply point. The charges are equal and opposite for generation and load at a point and vary between $\pm 10\%$. The loss factors are set six times a year, and announced three weeks ahead based on a forecast of system conditions
- a congestion charge which is the cost of transmission constraints on the network that result from Statnett's constraint management approach which is explained below
- an access charge which is paid by both generators and consuming users on a postage stamp basis (euro/kW), which is designed to recover the costs of Statnett's user connection equipment (viz switchyards); the costs of AC interconnecting lines with Sweden, Finland and the interconnection with **Russia**, and the costs of n-1 reliability
- a power charge which is paid by both generators and consuming users on a postage stamp (euro/kW) based on measured supply or withdrawal at each grid meter point. It is the residual charge, which collects the income net of the three previous charges that is allowed by the regulatory formula

Statnett is subject to a revenue control of the CPI-X which is indexed to its historic costs. In addition, there is an incentive scheme for managing constraints.

The regulation market, the resolution of constraints, and the settlement of deviations from schedule

Market participants are responsible for submitting balanced schedules to Statnett that are balanced by zone. Generators have to submit provisional hourly production plans to Statnett by 19.00 hrs of the day ahead; the plans can be modified down to an hour ahead of run time.

Every day by 19.30 the generators and loads bid and offer to Statnett prices and quantities for each hour of the next day by which they will increase or decrease output from their planned output at 15 minutes notice. Statnett controls the stability of the system in real time through the stacks of bids and an instruction implies a transaction in the regulation market, which is paid for at the price of the generator whose bid is at the margin in the regulation market. Contractual positions are submitted after the day of trading, and imbalances between scheduled input and output are paid for at the "real time" regulation price.

When there are temporary constraints due to operational or maintenance reasons within a zone, then Statnett pays for the redispatch and so "buys out" the constraints, which is called "counterbuying". When Statnett "countertrades" it takes an appropriate offer or bid from those who offer or bid into

the regulation market, and it bears the difference in income between the regulation price and the price of the bid. When there are more enduring structural constraints within Norway and between Norway and Sweden, then NordPool splits into zonal submarkets.

FINLAND

Background to restructuring the electricity supply industry

The market was liberalised by the Electricity Market Act of 1995 which opened access to networks to all consumers with a load in excess of 500kW in 1996 and subsequently opened access to all consumers, and created the Electricity Market Authority. The Finnish Options Market set up El-Ex, a continuously traded bid-offer exchange market that offered its EL-BAS product which is a 1MW hour block for physical delivery that closes two hours before run time. In 1998 Fingrid bought El-Ex and subsequently sold half to Svenska Kraftnät, and EL-EX extended its activities into Sweden with the EL-BAS product when Finland and Sweden removed their border tariffs on electricity, and NordPool provided the spot market in Finland (it became a price area within NordPool) through El-Ex acting as its agent.

Two main high voltage networks were developed in Finland, one by IVO, the Finnish State Power Company³³, and the other by TVS, a company owned³³ by PVO which in turn is owned by a group of energy intensive industries. In 1996 the government agreed with the owners that the two grids would be merged, and in 1997 Fingrid took over all of the 400kV and 220kV lines and half of the 110kV lines, and the interconnections to the neighbouring countries (Russia, Norway, and Sweden), and started operating the network. In 1999 Finland became a part of the Nordic market.

The organisation and responsibilities of Fingrid

Fingrid is a private company owned 12% by the government, 25% by Fortum, 25% by PVO, and the remaining 38% by a number of Finnish life insurance and pension fund groups. The ownership structure and internal decision-making rules guarantee that none of the parties has a dominant position either individually or together with another party in making major changes.

Under legislation Fingrid has a responsibility for developing the network, but it does not have a monopoly of building lines of 100kV and above – other parties can build such lines, and Fingrid has an understanding with the Electricity Market Authority that it would incorporate the lines within its network subject to reasonableness. Fingrid also has the responsibilities under legislation for:-

³³ Subsequently merged with Neste, the state petrochemicals company, to create Fortum.

- connecting users
- transmitting power
- charging reasonable rates
- treating users in a non-discriminatory manner
- operating the system in a stable manner

It is regulated in all its activities by the Electric Market Authority which sets Fingrid's tariffs in constant nominal prices for a period of 3 years.

Generators, distributors and directly connected end-use customers have always either provided for themselves or paid grid owners to build connections to the main grid, and this approach has been continued.

Fingrid's transmission charges and regulation

There are four components to Fingrid's charges:-

- a market access charge, which is paid by consuming users based on consumption plus losses of electricity beyond Fingrid's connection point. This charge recovers part³⁴ of the capital and operations and maintenance costs of the network
- a use of grid charge, which is based on how much electricity a consuming user takes through the connection point and is defined separately for winter business days and other times. This charge recovers the balance of the capital and operations and maintenance costs of the network
- a system service charge, which covers the costs of ancillary services and is charged to consuming users based on the consumption of all electrical energy beyond Fingrid's connection point by all consumers
- a losses charge, which is based on the forecast of average losses in the main grid, and is charged separately on both input to and output from the main grid

All of the charges are based entirely on energy flows (i.e. kWh) – there are no capacity or demand charges – and they are nationally uniform so Finland has a single energy price. Generators only pay the losses charge. Because both the system service charge and the losses charge are set for 3 years Fingrid has an incentive to manage (in the active sense) the related costs.

Fingrid has been spending about €35m (\$30m) annually on upgrading the network and expects that to increase to about €40m (\$36m).

³⁴ The split between the market access charge and the use of grid charge affects the charge paid by a distribution network which has a high level of embedded generation relative to the charge paid by a distribution network that has little embedded generation. The balance is politically determined.

The balancing market, the resolution of constraints, and the settlement of deviations from schedules

Forty minutes before run time market participants provide Fingrid System Operation with hourly schedules of forecast injection and extraction by grid supply point. They are supposed to balance their schedules. Suppliers and loads offer a schedule of capacity and related prices (euro/MWh) to regulate-up and regulate-down no later than 10 minutes before the start of the operating hour, and Fingrid System Operation stacks the bids and offers.

At the end of each hour, if there is no constraint then the price paid for regulation-up and -down power is defined as follows:-

- the regulation-up price to all parties who provided regulation-up power is the price of the most expensive increase of generation (or reduction of consumption) called for regulation during each hour (reg +), i.e. it is a market clearing price for regulation-up
- the regulation-down price paid to all parties who provided regulation-down is the price of the cheapest reduction of generation (or increase of consumption) called for regulation during each hour (reg -), i.e. it is a market clearing price for regulation-down

The price charged for balance power is based on a two-price system, namely separate prices are defined for the purchase and sale of balance power, and the price paid by a party that is not balanced depends upon the regulation Fingrid requires and what the party needs as:-

- the price of balance power bought from Fingrid will be the highest regulation-up price during the hour. If there has been no regulation-up, then the sale price for balance power is the day-ahead NordPool price in the Finnish price zone
- the price of balance power sold to Fingrid will be the lowest regulation-down price used during the hour. If there has been no regulation-down, then the purchase for balance power is the day-ahead NordPool price in the Finnish price zone

The charging can be summarised as follows:-

	Fingrid regulates-up	Fingrid regulates-down	Fingrid requires no regulation
positive imbalance	spot price	reg -	spot price
negative imbalance	reg +	spot price	spot price

When there is a constraint Fingrid calls for “special regulation” to resolve it. The bid is excluded from the stack for pricing regulation, and the party providing the regulation is paid its bid. (Note that the price of the regulation-up which is used in special regulation will always be the same or

higher than the regulation-up price. The price of regulation-down used in special regulation will always be the same or lower than the regulation-down price).

Market participants (including NordPool) are responsible for providing the Balance Unit (which is a functionally separate part of Fingrid which produces its own accounts) with details of all of their contracts. It also receives information on all metered flows, and computes a settlement for balances.

Annex 2 THE INSTITUTIONAL FRAMEWORKS OF TRANSMISSION, SYSTEM OPERATION AND MARKETS IN ARGENTINA, AUSTRALIA, AND NEW ZEALAND

Argentina

In Argentina, Companhia Administradora del Mercado Mayorista Electrico, SA (CMMESA) - a not-for-profit company that was created following legislation with a board of stakeholder representatives and a representative of the Secretary of Energy - is responsible for both system operation and for running not only the mandatory day ahead spot market but also the forward contracts market. CMMESA runs a centralised optimised dispatch that creates real time nodal marginal prices (including marginal losses). There was a proposal that Cmmesa should also operate a day ahead market, but it has not been implemented. Transener – the high voltage company which owns most of the 220kV and 500kV facilities – is a pure wires and poles business which is responsible only for ensuring that its *existing* assets are in service; it has no responsibility for developing the network.

There has been no central planning for upgrading the system; it is left to the initiative of the users of the system to come forward with proposals for developing new facilities, and (by majority) to agree to pay for the costs of those facilities. The principle is that those who bear the costs of congestion should be responsible for, and have the means of, mitigating it. New lines are put out to a build/own/operate competitive tender on 95 year concessions.

Australia

In December 1998, following the lead set by the liberalisation in the state of Victoria, Australia introduced the “National Electricity Market” which operates across the four interconnected states of Queensland, New South Wales, Victoria and South Australia, and the Australian Capital Territory³⁵. The National Electricity Market Management Company (NEMMCO) is responsible for system operation and for running and administering a mandatory spot market which generates zonal prices every five minutes in five market regions (whose boundaries are broadly aligned to State boundaries but do not coincide exactly, and the Snowy Mountain area) and has a half hourly trading period wherein trading prices are based on the time weighted average of the 5 minute dispatch prices. NEMMCO is a not-for-profit public company limited by guarantee which has members but not shareholders. The current members are the four states and the Australian Capital Territory who each nominate a member. The Sydney Futures and Options Market offers a range of monthly futures

³⁵ This comprises the capital city Canberra and surrounding areas including the Snowy Mountain hydro complex and is embedded in New South Wales.

contracts referenced to the Sydney and Melbourne regional nodal prices – trading in these futures contracts can be up to 12 months ahead.

The organisation and responsibilities for the ownership and development of transmission are State based and differ among the states. Thus, for example, in New South Wales Transgrid is a statutory corporation owned by the State government and is not only the asset owner, it also has the responsibility for developing the network. In contrast in Victoria SPI PowerNet is privately owned (it was privatised by a trade sale in 1996 when it was bought by GPU, who recently sold it to Singapore Power International). PowerNet is only responsible for operating its existing network, connecting new users to its network and for undertaking minor developments on the shared network facilities costing less than about \$1m. VenCorp is the interface between transmission users and transmission, “buying” transmission service from PowerNet in a similar manner to the way in which a US ISO acts as an administrative interface between transmission users and transmission owners. In addition VenCorp is an independent transmission planner, responsible for determining the need for development of the transmission network. It then either authorises PowerNet to undertake minor developments, or prepares and invites tenders on a build/own/maintain basis for the development of major facilities.

New Zealand

The restructuring of the electricity supply industry in New Zealand has been a long drawn out affair that started in 1987 when New Zealand had some 60 municipally owned and cooperative distributors and a generation and transmission monopoly that was part of the government administration. All of the distributors were converted into companies and some have been privatised, and the generation and transmission was formed into a state corporation, the Electricity Corporation of New Zealand (ECNZ). In 1994 the national transmission grid and system operation was split off from ECNZ to form Transpower which is – and remains – owned by the government. The principal functions of Transpower are to:-

- own the transmission assets and offer their use on non-discriminatory terms
- operate the system to reliable standards
- develop proposals for the expansion of the grid, but (apart from investment that will reduce its operations and maintenance costs) it does not implement them unless they are supported by connected grid users signing "investment contracts" in which they determine the main dimensions of the assets such as transformer capacity or transmission line MVA capacity. It is planned that investors will receive financial transmission rights

Over the period 1996 to 1999 in a two-step process the state generation corporation was split into first two companies then four companies and one of them has been privatised. In 1996 the industry created the New Zealand Electricity Market (NZEM), which is a multilateral agreement between those who wish to participate in wholesale trading. The market rules are known as the NZEM Rulebook³⁶, which is governed by a Rules Committee comprised representatives of market participants. M-Co is a for profit limited company created to administer the NZEM in its capacity as market administrator. It was initially owned by ECNZ, Transpower and the Electricity Supply Association of New Zealand, but was sold to the Australian subsidiary of the Rand Bank of South African.

The NZEM rules are based on a contractual model that identifies a number of specific market operational roles to be carried out by service providers of which the principal ones are:-

- scheduler;
- dispatcher;
- grid operator
- clearing manager;
- reconciliation manager;
- settlement manager; and
- market administrator.

The Rules state that the service provider roles will be tendered out at regular intervals (typically five or six years). In reality, however, a number of these roles are entrenched, and the tendering process is intended simply to enhance transparency and accountability in the selection process³⁷. The initial contracts for the service providers were placed with:-

- M-Co, which is provider for pricing, clearing and settlement
- Transpower, which is service provider for grid operation, scheduling, dispatch, and reconciliation

In summary the spot market functions as follows. Each day by 13.00 hours generators and purchasers wishing to trade in the spot market the following day submit provisional offers to supply and bids to take for each of the approximately 250 nodal points where energy is traded, and the grid

³⁶ NZEM also acts as an umbrella for the development of retail trading. In place of the NZEM rulebook, the Metering and Reconciliation Information Agreement (MARIA) establishes technical metering and reconciliation standards necessary for retail competition.

³⁷ Governance is currently under review and the government is in the process of replacing the Rules Committee with an Electricity Governance Board that will also hold jurisdiction of other rules for administration of physical security and retail trading. The contractual model for the appointment of service providers will endure.

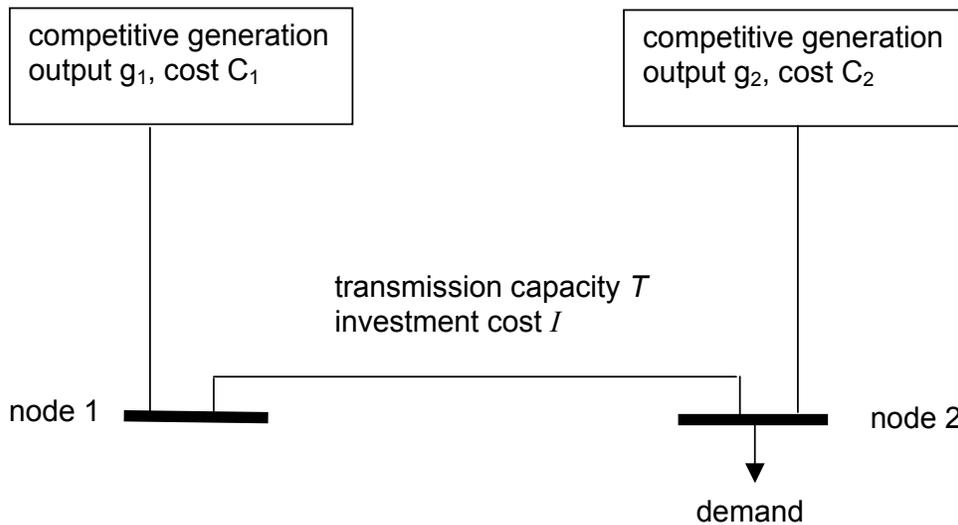
operator submits information about the transfer capacities of the grid. The offers and bids are used to prepare for each half hour a predispatch schedule (which Transpower reviews to check for system security), and final offers are made one hour before each half hour of trading which Transpower uses to dispatch the system and to calculate prices ex-post. Provisional prices are communicated to the market within the week and final prices are notified typically by the end of the following month. Additionally new rules have been introduced that enable Transpower to release indicative prices in the run up to despatch (termed despatch price) but these have no formal status.

The original design of the market envisaged that there would also be a day ahead ex-ante commitment market, but the market stopped through lack of interest within days.

Annex 3 NODAL LMP DOES NOT GENERALLY GIVE THE SOCIALLY OPTIMAL SIGNALS FOR TRANSMISSION EXPANSION³⁸

Model

Consider a situation where remote generation at node 1 competes with local generation to supply demand at node 2 through a link with capacity T that costs I to build. It is assumed that generation costs at node 1 (C_1) are less than those at node 2 (C_2), so that the transmission link is always operated at its maximum capacity T . The situation can be depicted as follows:-



Efficient level of transmission capacity

The most efficient level of transmission capacity is that which minimises total cost. Assuming for simplicity that all variables apply to a fixed period of constant operation, the total cost of supplying the demand is

$$C_1(g_1) + C_2(g_2) + I(T)$$

where $I(T)$ is the cost of providing transmission capacity T . Investment to increase T should progress until the incremental reduction in total cost is zero, i.e. until

$$\frac{dC_1}{dg_1} \frac{dg_1}{dT} + \frac{dC_2}{dg_2} \frac{dg_2}{dT} + \frac{dI}{dT} = 0$$

or

$$\frac{dI}{dT} = P_2 - P_1$$

where P_1 and P_2 are the LMPs at nodes 1 and 2 respectively.

³⁸ There are some extreme situations where LMP does give correct prices.

Level of transmission capacity incentivised by financial transmission rights

Suppose that the transmission investor (assumed for present purposes to have no financial interest in the energy market) is incentivised by granting to him a financial right to receive a payment priced at $(P_2 - P_1)$ on all energy transmitted. The incentive to invest in capacity is then

$$T(P_2 - P_1) - I(T)$$

In most cases on mature AC transmission systems, this incentive decreases with increasing capacity, and so will not result in any investment at all. If, however, investment does provide a net benefit, it will proceed until the incremental change in benefit is zero, i.e. until

$$\frac{dI}{dT} = \frac{d}{dT} [T(P_2 - P_1)]$$

$$\frac{dI}{dT} = P_2 - P_1 + T \left[\frac{dP_2}{dT} - \frac{dP_1}{dT} \right]$$

Except for rare special cases in which P_2 and P_1 are nearly independent of T , this criterion is very different from that derived above for efficient investment.

Annex 4 BRIEF CURRICULUM VITAE

Alex Henney studied engineering at the Universities of Bristol, England, and Virginia where he was a Fulbright Scholar, and economics at the London School of Economics. He worked for McKinsey & Co. and the British Civil Service, and was a board director of London Electricity in the early 1980s. In February 1987, as Chairman of the Working Group on the Electricity Supply Industry at the Centre for Policy Studies (which was set up by Mrs. Thatcher), he published a report that advocated restructuring the electricity industry in England & Wales to create a competitive market including a separate grid and a pool as a spot market. Subsequently he has worked on electricity market restructuring and market issues in the Nordic countries, other European countries, and the US, and was the founding secretary of the international Association of Power Exchanges which was conceived at a conference he organized in Washington. He recently completed a major study looking at transmission pricing in ten competitive markets around the world “Transmission pricing in competitive markets”. In 1997 he was the first person to propose reforming the Pool of England & Wales, and is currently undertaking a review of how the New Electricity Trading Arrangements are operating.

Tim Russell studied electrical engineering at Imperial College, London. He started his career in 1976 in the network Development Section of the Central Electricity Generating Board and then joined London Electricity, where he became section head, responsible for all operational planning on the high voltage (11kV to 132kV) systems. He returned to the Generating Board, undertaking transmission system analysis on the 400kV system and prepared the transmission outage plans for 1998 and 1989. With privatisation he joined National Power as Grid Issues Manager, responsible for the charges National Power pays to the National Grid Company and to Distribution Companies for using their systems and the sale of ancillary services. On behalf of National Power US he participated in the debate over restructuring in the USA. Since leaving National Power he has undertaken various assignments in Britain and two continental countries related to transmission issues.