INTERNATIONAL REVIEW OF TRANSMISSION PLANNING ARRANGEMENTS

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A report for the

Australian Energy Market Commission

The Brattle Group

rue Ducale 83
Bruxelles 1000
Belgium

tel: +32.2790.3580
fax: +32.2790.3581
office@brattle.be

The Brattle Group

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1 Introduction and summary

This study provides a factual description of transmission planning arrangements in international markets, in the context of the AEMC's ongoing development of a detailed implementation plan for the national electricity transmission planning function. The markets chosen are therefore ones with similar characteristics to Australia—i.e., liberalised markets served by more than one transmission company. We describe transmission planning arrangements in:

1. North America, with particular focus on California (the California ISO, "CAISO") and Alberta (the Alberta Electric System Operator, "AESO"), for reasons explained in the text.

2. The Nordic region ("Nordel") comprising Denmark, Finland, Norway and Sweden.

3. Great Britain (GB), comprising the three transmission systems that together serve the area (one in England and Wales, two in Scotland).

4. Continental Europe, where the Union for the Co-ordination of the Transmission of Electricity (UCTE) co-ordinates the transmission systems at operational level, but there is essentially no co-ordination of transmission planning. Our focus here is on current legislative proposals for reform.[1]

In light of the AEMC's review and the findings of the Energy Reform Implementation Group (ERIG),[2] we have paid particular attention to two key issues:

1. how different planning arrangements evaluate proposed transmission investments, in particular with regard to the distinction between "reliability" and "economic" investments; and

2. how different planning arrangements promote co-ordinated development of a transmission grid divided between multiple transmission owners ("TOs").[3]

Structure of this report

Each of the transmission planning systems we have reviewed is described in sections 2–5 of the report. For ease of comparability we have adopted a common structure for the description of

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[1] The proposals are made at EU level and therefore would in principle also affect the Nordel and GB regions, although in practice they are likely to focus on UCTE.

[2] *Energy Reform: The Way Forward for Australia—a report to the Council of Australian Governments by the Energy Reform Implementation Group*, ERIG, January 2007.

[3] Where relevant, in this report we distinguish between System Operator (SO) and Transmission Owner (TO) functions. In some jurisdictions these can be discharged by separate, unrelated organisations. In describing US markets we refer to ISOs (Independent System Operator) to describe the organisation which carries out the SO role. Where the transmission system is owned and operated by one and the same organisation we refer to the TSO (Transmission System Owner/Operator).

the systems (with the exception of continental Europe, for reasons explained in the text). Each section therefore describes in successive sub-sections:

- the organisation of the industry and its regulation;
- the planning arrangements in general;
- how "reliability" and "economic" investments are assessed for planning purposes;
- how the relevant parties are encouraged to co-ordinate on transmission planning; and
- significant recent and/or proposed changes to the planning arrangements, and the thinking around those changes.

It is beyond the scope of this report to assess the success of different arrangements. However, this summary section is intended to draw out some key issues and differences in transmission planning arrangements seen in different markets, based on the findings of our review.

1.2 Overview of markets chosen

With some exceptions, all of the regions studied have more-or-less liberalised energy markets, with wholesale market competition on the basis of competing generators using a common transmission system, and all are subject to independent (at least in principle) economic regulation. However, there are significant differences in institutions and market structure.

- The extent to which they fall under a single jurisdiction varies considerably. At one extreme, the GB system falls under a single economic regulator, Ofgem, and a single political entity (the UK government) with relevant competences (except in the area of planning permission). More typically, the other systems exist under fragmented regulatory and political systems, with different competences falling to various state and federal authorities.
- Although all systems have multiple TOs there are significant differences in transmission ownership. In some cases the grid belongs to vertically integrated utilities (with or without some form of independent SO), in other cases it belongs to a "pure transco" that has no other activities. There is also a mix of ownership forms between private and state ownership.
- There is a related distinction between non-profit (in the US) and for-profit (UK) SOs.
- There are also varying levels of concentration and competition, with reasonably high levels of competition in GB, Nordel and much of North America, and rather lower levels in large parts of continental Europe.
- Most systems use some kind of locational power pricing for congestion management. Some use full-blown locational marginal pricing ("LMP") to capture congestion at all levels within the system. In other cases price differences only arise across regional boundaries: under the market-splitting regime of Nordpool each country can have only one or a small number of distinct price zones, while in much of continental Europe each country has a single price and price differences are only seen across

national borders, where congestion is managed via explicit auctions of physical capacity on congested links. The GB and Alberta systems socialise all congestion costs to ensure a single price across the system at any point in time.

- Systems vary greatly in their use of incentives for operational and capital efficiency by transmission operators and owners. GB has a particularly strong commitment to the use of explicit incentives, including on transmission losses and service quality (GB and Norway are the only countries we are aware of that provide explicit financial incentives for the latter). The traditional US system also provides strong efficiency incentives for TOs, because rates can remain unchanged for significant periods of time, allowing the TO to profit from cost reductions. By contrast, Alberta and many parts of Europe have a cost pass-through approach (and state-owned grid companies that might in any case have limited interest in financial incentives).

1.3 Transmission planning arrangements

1.3.1 Planning processes

At high level there are many commonalities in the transmission planning processes followed in the different jurisdictions studied. All planners produce forecasts of load and generation growth, using some combination of aggregate-level/macroeconomic forecasts (particularly for longer time horizons) and detailed projections aggregated from sources such as connection requests and inquiries, and customer surveys. The forecasts go out over a timeframe that reflects the long lead time for transmission investments, varying from seven years (in the UK) to ten and even—in less detail—twenty years (in Alberta). They are used to produce power flow forecasts and assess transmission system needs going forwards. With the exception of continental Europe, where no regional plan exists, there is some process that leads to a more-or-less high level plan in response to these forecasts.

However, within that broad picture there are a number of significant differences. First, there is the question of whether the high-level plan is itself a concrete investment plan (identifying specific lines), or is closer to an assessment of necessary transmission capacities (e.g., identifying the need for additional capacities on specified zonal borders). In GB, for example, the role of the overall planner (the GB System Operator, "GBSO") is essentially limited to producing the forecasts and power flow modelling described above. The individual TOs then produce investment plans, and the GBSO checks them for consistency with its overall planning assumptions and flow modelling. However, responsibility for planning the networks to continue to meet the relevant standards lies with the TOs. At the other extreme, in Alberta the planning process resides very much with the AESO, and individual TOs are obliged to produce their own proposals in concordance with the AESO view.

There is also significant variation in the extent of regulatory oversight of the process, and in its general transparency. In the US for example, the federal regulator has laid down clear principles for transmission planning, and all ISOs and TOs outside ISOs are obliged to submit their planning processes for regulatory approval. The level of transparency is extremely high, with all major documents published, extensive stakeholder consultation, and public regulatory proceedings. At the other extreme, the Nordic approach to inter-national planning is entirely voluntary. The Nordel processes are therefore arrived at by negotiation between the Nordic TSOs, there is little regulatory oversight, and the level of transparency is relatively low (for example, cost–benefit studies of potential upgrades are performed but not published by Nordel).

1.3.2 Implementation and cost recovery

Again there is a high level commonality of approaches to implementation, since in almost all cases a TO eventually makes the actual investments, subject to regulatory approval, and recovers the costs via its ratebase. Similarly, it is the TO that carries out detailed planning (e.g., easement acquisition). Most systems also have some room for "merchant transmission", where the investor invests at risk and earns a return from congestion rents and/or unregulated access charges. Merchant transmission usually links geographically distinct systems.

However, there are again important differences between systems. First is the extent to which the transmission plan is mandatory. At one extreme, as in Nordel, the plan can be entirely indicative/optional. At the other extreme, the planner can, as in Alberta, have the right to compel investment by the TO, or, as in California, tender for a third party to carry out the work.

Second is the mechanism for cost recovery, where a key issue appears to be the ability of the system to compensate parties who lose from transmission investment. This has at least two dimensions. First there can be losses simply arising from the cost of an investment. For example, if increased trade between areas A and B leads to a requirement for reinforcement in area C, and the TO in area C can only recover costs from customers connected to its own network, then they will be losers. The area C owner may therefore encounter considerable political opposition if it seeks approval for reinforcements of this kind. Second, there can be losses as a result of the market impact of transmission reinforcements. For example, if area A has lower prices than area B, and there is only limited export capacity from A to B, then there may be a strong economic case for increasing that export capacity. However, that increase will often lead to higher prices in A and lower prices in B, and may therefore encounter opposition from consumers in A and producers in B.

Most of the systems we have looked at have therefore evolved or are in the process of evolving some mechanism to allow for a fairer sharing of the costs and benefits of transmission. In some systems (e.g., GB, California, Alberta) the SO collects transmission tariffs from all users into a "single pot", and they are then paid out to the individual TOs on the basis of regulated revenues, thus addressing the first of these problems. In some systems (e.g., Alberta) these tariffs are uniform, but in others (e.g., GB) they are not –the key point is not that the charges are uniform but that they can be aggregated and redistributed among TOs. Although there is no theoretical reason why this approach requires a single SO (or other single body collecting transmission tariffs) to work, European experience with the Inter-TSO Compensation Scheme suggests that in practice it may be very difficult.

1.3.3 Responding to market needs

A common theme from our study is the primary role of forecasting in assessing market needs, as opposed to "market signals". As described above, all systems make extensive use of load and generation forecasts derived from macroeconomic and/or more detailed sources. These sources will include connection requests, which can be considered a kind of market signal. In addition, most systems make some use of other market signals such as the proportion of time that a link is congested, and differences in spot and forward prices across congested borders.

But these market signals are mainly a source of information, with the exception of connection requests. No-one relies purely or even mainly on market signals to develop transmission investment plans, in the sense that (for example) there is no system where the planner holds an "open season" of some kind, assembles financially committed bids and then chooses a set of investments that will enable it to meet these bids. In the report we describe some of the discussion that has gone on around this issue—for example, in GB there was considerable interest at one point in attempting to develop such a system, and also considerable controversy. Opponents of the idea argue that:

- transmission networks are too enmeshed to easily define a "product" that can be offered on the market;
- economies of scale and scope, and in particular the lumpiness of transmission investment, are such that it can be much more efficient to build in advance of demand; and
- the lead times for transmission investment are significantly longer than for generation or load, so that market signals will typically come too late.

We also identify a range of different incentives to respond to market need for transmission capacity (along with a salient common factor—the high political/reputational cost of system problems arising from failure to meet reliability standards). In all markets where transmission ownership is integrated with generation and/or supply, the issue of incentives is central to the debate, with high levels of concern that transmission investment, as well as operation of the network, will be biased toward the interests of the owner's generation/supply affiliates. In Europe this has been identified as a key barrier to increasing interconnection between national markets, and in the US it lay behind the whole development of ISOs/RTOs, including their planning functions.

In many systems there has been under-investment in transmission in recent years, which has led to the adoption by regulators of enhanced rates of return on new investment. In the US, the Federal Energy Regulatory Commission (FERC) offers such an incentive. For example, in one decision last year the, FERC allowed a 1% elevation in the rate of return on equity as an explicit incentive for new investment in the transmission system. Finally, as discussed above, most systems also allow for some kind of merchant investment that can earn an unregulated return (European legislation lays out specific tests for this, analogous to the "revocation of coverage" test that is applied to Australian pipelines).

1.3.4 Trading off transmission and non-transmission investments

In principle there may be significant efficiency savings in some circumstances from substituting a non-transmission investment for a transmission upgrade. For example, it may be possible to avoid the need to upgrade a line to a constrained area by building a peaking unit in the area, or signing a system support contract that allows the SO to interrupt a large industrial user.

Systems differ in the weight they put on this trade-off, and how they seek to achieve it. At one extreme, some planners believe that at least in specific areas there may be little discretion in the location of generation and load, and that it is therefore the role of the transmission planner simply to meet the needs of system users. However, some other systems have developed quite elaborate locational pricing regimes and/or “deep connection charges” intended to ensure that locational decisions are made taking into account their impact on the transmission system.

In Europe only GB, Norway and Sweden currently have a locational element in their transmission tariffs, but recent legislative proposals from the European Commission include a reference to “the provision of appropriate and efficient locational signals”. In some parts of North America new generators are charged a “deep connection charge” that reflects the cost of upgrades to the system that their connection induces. However, in other places there is a commitment to equal tariffs regardless of location, partly out a belief that this will facilitate the development of competition.

1.4 “Reliability” and “economic” investments

Most transmission planning methodologies distinguish between investments made to meet technical “reliability” standards (e.g., “n–1” criteria), and those made on “economic” grounds. The logic behind this distinction is questionable.[4] Investments made on the basis of technical standards will nonetheless have significant effects on congestion, pricing etc, while investments made to relive congestion and foster competition will nonetheless impact reliability. Moreover, reliability itself has an economic value that can and routinely is used in (for example) generation adequacy assessments.

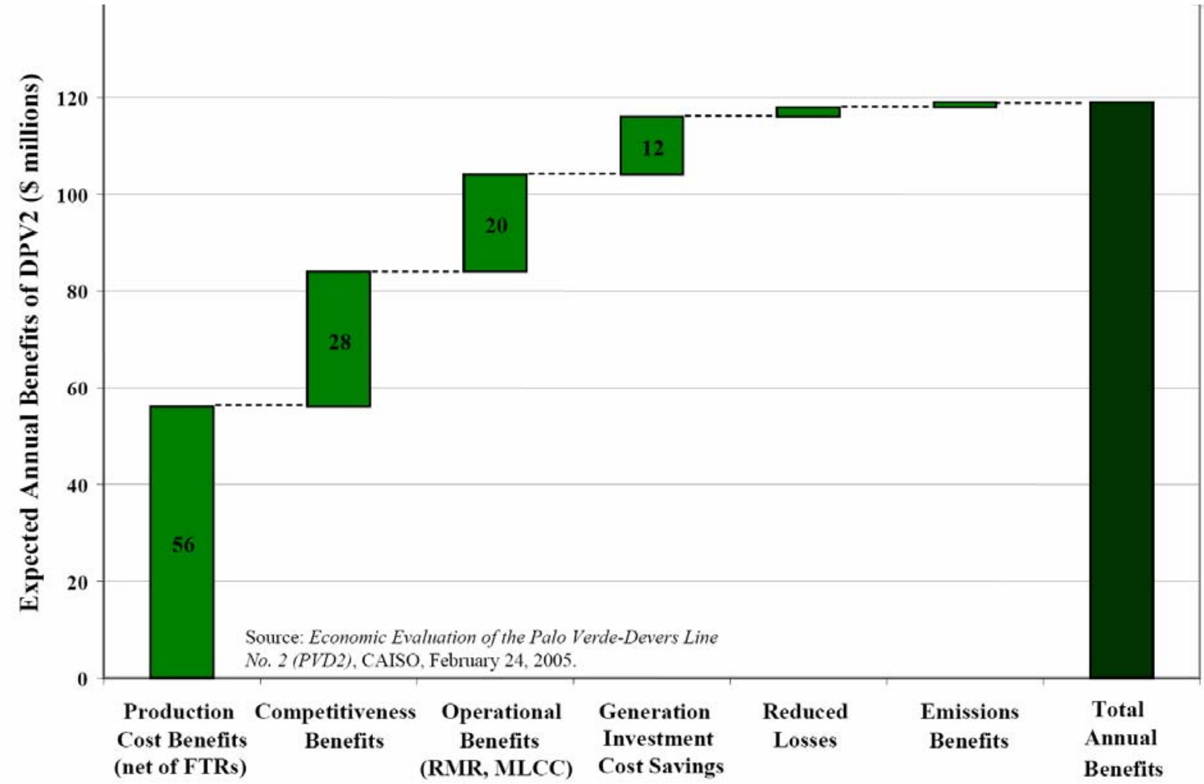
Nonetheless, the distinction is important in understanding the real world practice of transmission planning. All transmission planning begins with a requirement to plan to meet reliability standards, which were set by engineers prior to liberalisation and have in all cases that we aware of persisted as “legacy” arrangements in liberalised markets. Beyond reliability, however, there is a major difference between the majority of systems, where investments not required to meet the technical criteria must be shown to satisfy a cost–benefit test, and a minority of systems where (as in Alberta) there is a generic policy to build sufficient infrastructure to avoid persistent congestion, thus promoting trading liquidity and helping to support the development of a competitive market.

Within the areas where cost–benefit tests are applied, there is a range of approaches taken to the measurement of benefits. Most systems follow a “traditional” approach that models only savings in production costs. However, it is increasingly recognised that this approach under-estimates the benefits of transmission upgrades, which can also include increased reliability, enhanced competition, lower generation investment costs and other factors. The most comprehensive cost–benefit framework formally specified by a transmission planner we are

[4] It has been described by one eminent economist as “a complete fiction” (*Patterns of Transmission Investment*, Paul Joskow, MIT 2005, p. 12), and in a recent US industry-sponsored expert report as “outdated and no-longer-useful” (*A National Perspective on allocating the costs of new transmission investment: practice and principles*, WIRES 2007, p. 17).

aware of is the Transmission Economic Assessment Methodology ("TEAM") recently adopted by the California ISO. As Figure 1 illustrates, it estimates quantitative values for a number of benefits other than savings in production costs, and in the case shown produces a much (over 100%) higher estimate of total benefits as a result.

Figure 1: Benefits of Transmission Upgrade DPV2[5]



1.5 Co-ordination of transmission planning

Based on the above, international experience highlights a number of factors that appear to be considered central to achieving co-ordinated investment planning among multiple TOs. First is the creation of institutions with the appropriate remit and technical expertise to co-ordinate a planning process effectively. Here opinions differ as to whether co-operation through this institution should be voluntary or mandatory. Proponents of the Nordel system argue that its voluntary nature makes it efficient, un-bureaucratic and free of political interference. However, even within Nordel there are critics, notably the Norwegian TSO, who claim that the system is too slow, and is incapable of overcoming national interests.

Second is the issue of incentives for co-operation. The issue of vertical integration is central for many systems. In the absence of vertical integration, a key focus is the existence of cost allocation mechanisms that allow for transfers between TOs, so as to minimise the creation of

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[5] Taken from *Evaluating the Economic Benefits of Transmission Investments*, by Johannes P. Pfeifenberger and Samuel A. Newell of *The Brattle Group*, presentation at EUCI's Cost-Effective Transmission Technology Conference, Nashville, TN, May 3rd 2007.

"winners and losers". Most systems have evolved toward increasing flexibility in cost allocation, notably by moving away from traditional methodologies that only allowed TOs to earn revenues from charges made to their own connected customers. Thus, in GB each TO has a regulated revenue allowance, paid by the GBSO, and the GBSO sets its tariffs for all users following the same methodology, which is designed to recover the total revenue allowances of the three TOs. In California the cost of new high-voltage transmission wires is spread across all system users irrespective of whether the users are connected to the network which owns the new assets. Experience suggests that this is a key factor in enhancing the chances of successful co-operation.

This kind of cost transfer mechanism seems to work better in arrangements that involve more formal co-operation, as seen in GB and the US, than in looser voluntary or quasi-voluntary settings such as Nordel and UCTE.

1.6 Key choices in the design of transmission planning arrangements

In this factual review of transmission planning arrangements we have not attempted to judge whether a particular set-up works well or better than another. However, we can identify three choices in the design of the arrangements which distinguish the arrangements we have reviewed and which seem particularly important.

1. **Institutional design**: in particular the extent to which participation in regional planning—including implementation of the plan's proposals—is mandatory for TOs.

2. **Funding across Transmission Owners**: where planning spans networks belonging to several different TOs, there is a choice over whether and how to allow for costs incurred by one owner to be charged to customers connected to the networks of the other owners. This might not be allowed, or, if it is, can be achieved through payments between the owners, or by pooling and then redistributing the charges paid by all network users.

3. **Cost–benefit test**: there is a choice over how to test the benefits of possible network upgrades. This might be a narrow test looking at the impact of investment on congestion costs, or could be a broader test taking into account other benefits, such as the impact on wholesale market competition, losses, and so on. Where a wider test of benefits is used, there may also be a choice of perspectives—e.g., end-consumer benefits only, or consumers and producers, and benefits can be assessed only within the region or across all interconnected regions.

Table 1 overleaf presents a brief summary of the markets studied in this report, including a description of where they stand with regard to each of these three key choices.

Table 1: Overview of markets studied

Market	CAISO	Alberta	Nordic	Great Britain	UCTE
Characteristics					
Peak demand (GW)	50	9.4	67	63	376
Network length (1,000 km)	41	21	approx. 40	40	220
Area (1,000 km^2)	300	660	1,200	210	approx 4,000
Number of SOs	1	1	4	1	27
Number of TOs	3 large	3 large	4 large	3	27
Ownership structure	Vertical integration, some independent generation, independent SO, large TOs privately owned	Vertical integration, some independent generation, independent SO, two TOs privately owned, third public	Independent TSOs (some cross ownership in Finland), state owned	One independent TSO, two vertically-integrated TOs	About half independent TSOs, half vertically integrated
Nature of planning body/process	Compulsory participation in process led by ISO, ISO may tender for investment if TOs refuse	ISO carries out planning and directs TOs to invest	Voluntary grouping carries out planning	Compulsory participation, limited SO role	Voluntary and bilateral, no central planning
Funding across TOs	Yes: cost of high voltage assets shared over all network users	Yes: network charges paid to ISO which pays regulated revenues to TOs in proportion to their costs	No: interconnections partly funded out of congestion revenues, rest from individual TSO charges	Yes: network charges paid to SO which pays regulated revenues to TOs in proportion to their costs	Partial: TSOs compensate each other for transit and loop flows, but mechanism functions poorly
Use of cost–benefit assessment	Detailed assessment methodology has been developed	No. Legal requirement that there should be no persistent congestion	Methodology but no details published	Limited methodology but not detailed and seems to play limited role	Unclear (no uniform methodology)

Figures taken from TSO websites

2 North America

In this section we present an overview of transmission planning in North America. North America has thousands of TOs, and planning occurs at a variety of levels: the individual utility/transmission service provider, Independent System Operator/Regional Transmission Organisations (ISOs/RTOs)[6] and beyond, as described below. It would be pointless to attempt a comprehensive survey, and in any case there are many commonalities across the continent. Instead we give an overview here, focusing on points that are likely to be of most relevance to Australia. We draw on examples from a number of different ISOs/RTOs, with a particular focus on the California ISO ("CAISO"), and the Alberta ISO (the Alberta Electric System Operator, "AESO"). We believe that the CAISO is a particularly instructive example because of the way it has met and responded to significant challenges in getting appropriate investment in transmission. In particular the "TEAM" methodology that the CAISO has developed for assessing "economic investments" is rather unique in terms of its breadth and sophistication. The AESO is interesting because it has a fundamentally different approach to assessing transmission need, based on an explicit policy decision to adopt a "predict-and-provide" approach rather than attempting to assess the net balance of costs and benefits from transmission upgrades (even when not required for reliability in the traditional sense).

2.1 Background

2.1.1 *Industry structure*

Many electric utilities in the US remain vertically integrated with all parts of the business (including generation) subject to economic regulation. In states where market reform and restructuring have taken place, formal wholesale markets have been created (i.e., centralized day-ahead and real-time spot markets for energy and certain ancillary generation services), and at least some generators are free to sell their output at market rates and are not subject to economic regulation. Much of the transmission network is owned by integrated utilities, but, as explained below, in many cases operation of the networks and dispatch of generators has been transferred to ISOs.

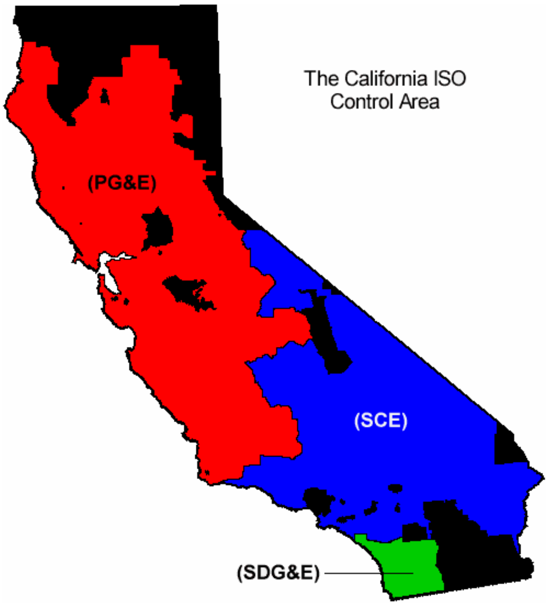
In California most of the transmission system is owned by three integrated and privately-owned utilities: Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric. These utilities also own many of the generating assets in California.[7] There are also a large number of mostly small municipal utilities, which in some cases own transmission assets and generation, and there are a number of independent merchant generators. The transmission

[6] The distinction between ISOs and RTOs is only in how they satisfy certain regulatory requirements. Both types of organization independently operate the transmission operators. RTOs, however, must satisfy stricter standards, e.g., in terms of governance, geographic scope and configuration.

[7] California's 1996 restructuring law required the three privately-owned utilities to divest their fossil-fired generation to independent generating companies. However, the utilities retained ownership of their nuclear and hydroelectric generating units. Over the last several years, these utilities have expanded their generation portfolio through the purchase of, or long-term contractual commitments with, new generating units.

systems of the three large utilities are operated by the CAISO.[8] The networks of these three utilities (PG&E, SCE, and SDG&E), which comprise slightly over 75% of California's transmission grid, are shown in Figure 2. The black areas on the map are the service territories of municipal utilities which are not part of the CAISO.

Figure 2: CAISO territory[9]



The industry structure in Alberta is similar: there are three large integrated utilities, one publicly owned, and an independent organisation, the AESO, operates the transmission networks.

2.1.2 Regulation

Regulation of the electricity industry in the USA is complicated by the existence of several regulatory bodies at the local (state) and national level, and the nature of the framework depends on whether the industry remains fully vertically integrated or has been restructured.

Throughout the US, FERC regulates much of the framework for transmission investment. In areas where transmission has been unbundled operationally and functionally through ISOs or RTOs, FERC approves and regulates ISOs and RTOs, and determines what planning activities these organizations must undertake in conjunction with the TOs (see below). Outside of these ISO/RTO markets, transmission planning generally is conducted by vertically-integrated utilities under the oversight of their state regulators and FERC. Contiguous utilities often will coordinate

[8] Several small municipal utilities have joined the CAISO but it appears that California's larger municipal utilities will remain outside of the CAISO for the foreseeable future.

[9] Map taken from the CAISO website. PG&E is Pacific Gas and Electric; SCE is Southern California Edison; and SDG&E is San Diego Gas and Electric.

on the planning of a major new line in the region, and under recent FERC rules,[10] utilities outside RTOs are also required to have a regional planning process.

Until recently, state and local governments had sole authority over the siting[11] of transmission lines. However, the *Energy Policy Act 2005* gave FERC and the Department of Energy (DoE) new powers over some aspects of transmission siting. The DoE is required to designate certain areas as "National Interest Electricity Transmission Corridors", for example if there is persistent serious congestion. The DoE designated two such regions in October 2007: the Mid-Atlantic Area National Corridor, covering parts of eight East Coast states and Washington DC, and the Southwest Area National Corridor, covering parts of southern California and western Arizona.[12] Once designated, FERC has the authority to approve the siting of transmission lines in such areas if they fail to gain the necessary approvals from state and local officials. For example, if state authorities lack the authority to permit an investment to go ahead because its benefits will fall outside the state, FERC may be able to approve the project under this new "backstop authority". FERC plans to examine projects which are rejected at state level as well as those which are not processed by state regulators in a timely fashion, although the former is controversial and may be subject to legal challenge.[13]

Jurisdiction over transmission rates is split between federal (i.e., FERC) and state regulators. State regulators (the state Public Utilities Commissions or "PUCs") have jurisdiction over the transmission component in bundled retail rates while FERC has jurisdiction over rates for unbundled transmission service and all wholesale power transactions. FERC also has jurisdiction over wholesale transmission rates in areas where transmission is managed by ISOs/RTOs.[14] FERC approves the transmission tariffs set by RTOs and therefore sets the required rate of return for at least the wholesale portion of both existing transmission assets and new investment in transmission capacity. In "restructured" states with retail access or states that have unbundled the transmission component of retail rates, the FERC-approved rates will also generally be applied to retail customers. In states that have not restructured or unbundled their retail electricity markets, state regulators set required rates of return for transmission assets through the bundled retail sales of the vertically-integrated utilities over which they have primary jurisdiction.

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[10] Order 890, discussed below.

[11] "Siting" is the process of seeking approval to build an asset (transmission line or generator). It is separate from the process of seeking to recover the costs of the asset ("ratemaking").

[12] *National Corridor Designations Order of October 2nd 2007*, US Department of Energy.

[13] *Regulations for Filing Applications for Permits to Site Interstate Electric Transmission Facilities*, FERC Order 689, November 2006. See also "Regional State Committees Can Help Provide a Regional Perspective to Planning and Siting Decisions, Reducing the Need for Federal Preemption", Gregory Basheda, *The Electricity Journal*, March 2006, vol. 19, No. 2, pp.43–51.

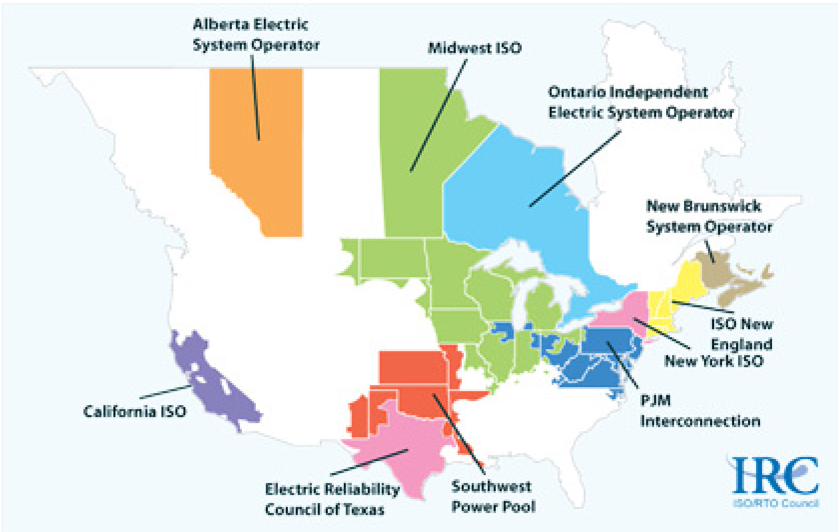
[14] All RTOs, ISOs, and other TOs under FERC jurisdiction (including investor-owned vertically-integrated utilities) must file open access transmission tariffs pursuant to FERC Order 888, issued April 1996. The rates charged in such tariffs are subject to FERC's jurisdiction. However, since most if not all of the transmission built by vertically-integrated utilities is designed to serve their native retail load, the costs of transmission assets are recovered primarily through rates set by state regulators.

The North American Electricity Reliability Corporation (NERC) is responsible for setting and enforcing reliability standards in the US, Canada, and parts of Mexico. NERC was founded in 1968 as a voluntary association of industry participants that set out rules for reliable operation of the electricity transmission system. Under the US Energy Policy Act of 2005, compliance with NERC standards approved by FERC became mandatory and enforceable (the strengthening of NERC's role followed widespread concern over the 2003 north-east US blackout). FERC approved 83 Reliability Standards in March 2007.[15] Voluntary compliance with NERC's additional standards is seen by FERC as industry good practice.

Neighbouring ISO/RTOs co-ordinate directly both bilaterally and through regional groupings such as the Western Electricity Coordinating Council (WECC), organised under NERC to take into account flows between ISO/RTO regions, and sub-regional planning groups that tend to focus on specific regional interconnectors (such as the Southwest Transmission Expansion Planning Group within WECC).

2.1.3 Transmission networks—ISOs and RTOs

Figure 3: ISOs/RTOs[16]



A significant portion of the North American electricity network is organised under an ISO or RTO model.[17] The ISO concept was developed to ensure non-discriminatory access to the transmission systems of vertically integrated utilities, and has evolved to also take on a greater role with respect to co-ordinating and planning the activities of many transmission-owning utilities within a region. The criteria for an RTO are set out by FERC in Order 2000 (see box).[18] It

[15] FERC Order 693, 118 FERC ¶ 61,218, 2007.

[16] ISO/RTO Council: http://www.isorto.org/site/c.jhKQIZPBImE/b.2604471/k.B14E/Map.htm.

[17] See, for example, the *IRC Handbook*, ISO/RTO Council, October 2007, which gives an overview of the 10 ISOs and RTOs in North America.

[18] *Regional Transmission Organisations*, 89 FERC ¶ 61,285 , 1999.

is hoped that all parts of the US transmission system should ultimately be managed by an ISO/RTO.

FERC Order 2000 describes four characteristics and eight minimum functions that an organisation must display in order to be approved by FERC as an RTO.

Four minimum characteristics of an RTO

1. Independence
   the RTO must be independent of market participants ("both in reality and in perception")
2. Scope and Regional Configuration
   the RTO control area must be defined to provide a sensible match with the RTO's functions, and this will include all or most of the network in a given area
3. Operational Authority
   the RTO must have operational control over the transmission facilities in its area, and it must be the "security co-ordinator"
4. Short-Term Reliability
   the RTO must have exclusive responsibility for short-term reliability of the grid

Eight minimum Functions of an RTO

1. Tariff Administration and Design
   the RTO must be the sole provider of transmission services, must set tariffs, and be the sole provider of new connections to the transmission network
2. Congestion Management
   the RTO must develop and operate market mechanisms to manage congestion
3. Parallel Path Flow
   the RTO must manage "parallel flow" (or "loop flow") issues on its network and on neighbouring networks; in practice RTOs will be sufficiently large to internalise most parallel flow issues
4. Ancillary Services
   the RTO must be a provider of last resort of ancillary services—market participants have the option of self-supply
5. OASIS (Open Access Same time Information System) and Total Transmission Capability (TTC) and Available Transmission Capability (ATC)
   the RTO must provide market participants with system information
6. Market Monitoring
   the RTO must undertaking market monitoring activities to aid in the prevention of market activities that are unduly discriminatory or preferential or provide opportunity for the exercise of market power
7. Planning and Expansion
   the RTO must have ultimate responsibility for both transmission planning and expansion within its region
8. Interregional Co-ordination
   the RTO must co-ordinate its activities with neighbouring control areas (whether RTOs exist there or not)

From the perspective of this study, the key requirement in the list is the seventh: "the RTO must have ultimate responsibility for both transmission planning and expansion within its region".

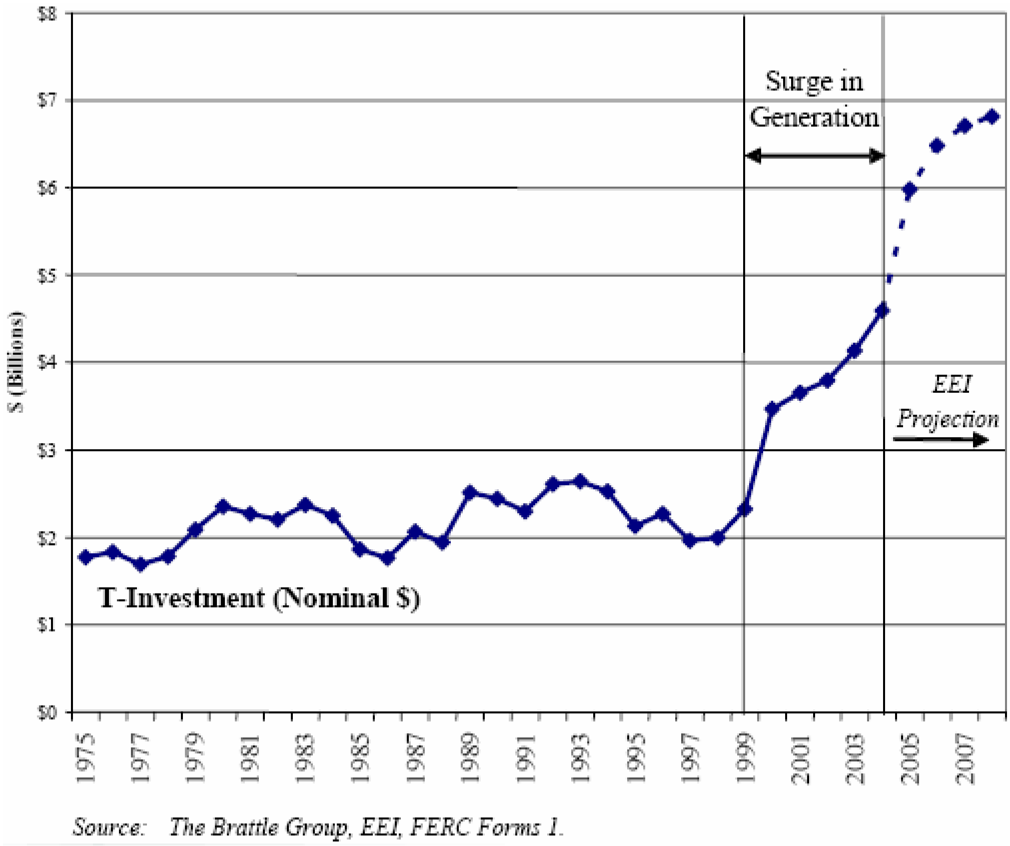
Congestion management

Congestion is generally held to be a significant issue: across the US transmission capacity has not increased in line with increases in peak demand.[19] Investment in transmission was declining in real terms from the mid 1970s until 2000, as illustrated in Figure 4. As a result, congestion

[19] *FERC Order 890 Preventing Undue Discrimination and Preference in Transmission Service*, FERC February 16 2007, paragraph 421.

costs have risen. In PJM[20] for example, they were as high as $2 billion in 2005, or up to 10% of total PJM costs.[21]

Figure 4: Transmission investments by investor-owned electric utilities[22]



In an ISO system such as CAISO or PJM, the ISO/RTO is responsible for managing congestion, for example by rescheduling generation whenever necessary. To ensure that certain generators stay in service (i.e., generators which make little money in the market but whose output sometimes is needed to maintain system reliability), the RTO will in some cases sign "must run" contracts with generators on the load side of a constraint. Many regions of the US have implemented a system of LMP, with different prices at each node of the high-voltage transmission system, set dynamically to reflect congestion as well as other factors (transmission losses).

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[20] PJM Interconnection coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

[21] *2006 State of the Market Report*, PJM.

[22] Taken from *Evaluating the Economic Benefits of Transmission Investments*, by Johannes P. Pfeifenberger and Samuel A. Newell of *The Brattle Group*, presentation at EUCI's Cost-Effective Transmission Technology Conference, Nashville, TN, May 3 2007.

2.1.4 Incentives on service quality and transmission losses

There are no direct financial incentives on TOs or ISOs/RTOs relating to service quality (e.g., number and duration of power cuts). As discussed above, NERC now has legal authority to enforce compliance with its technical engineering standards, and can levy fines. Avoiding damage to reputation is probably the main incentive for maintaining service quality.

There are also no direct financial incentives on TOs or ISOs/RTOs relating to losses on the transmission system. However, losses may be taken into account by ISOs/RTOs in cost–benefit assessment of "economic" transmission upgrades. For example, they are included explicitly in the CAISO "TEAM" process and in PJM's assessment of economic upgrades.

2.2 Transmission planning arrangements: key features

2.2.1 Transmission planning process

In the US, FERC sets the rules for transmission planning *processes*: all FERC-jurisdiction transmission service providers, whether ISOs/RTOs or individual investor-owned utilities, are required to have processes which comply with the FERC rules.[23] They must make public filings with FERC, explaining in detail how they comply, and FERC then approves or rejects these filings. The FERC process includes extensive consultation.

The relevant rules have recently been reformed and are set out in Order 890 (see box overleaf).[24] The planning process must be co-ordinated and open: for example, in addition to co-ordinating the investment of member TOs, network customers and other stakeholders must be fully involved in the planning process. As part of the planning process, the transmission service provider must publish all the relevant data and assumptions underlying its investment plans. FERC states that sufficient information must be made public that third-parties should be able to replicate the results of planning studies. The planning process must also take into account a regional perspective: the planner must co-ordinate with planners in adjacent interconnected systems to ensure that consistent planning assumptions are used, and in order to identify investments that would relieve constraints between systems.

In the consultation process leading up to the publication of order 890, FERC also considered whether it was necessary for integrated utilities (i.e., those owning both generation and transmission assets) not part of an ISO/RTO to engage an independent third party to conduct/oversee the planning process, in order to ensure that it was sufficiently non-discriminatory. However, FERC concluded that it was not necessary to mandate this for a number of reasons, including the fact that order 890 does require the planning process to be open and

[23] Publicly-owned utilities, such as municipal utilities, and electric cooperatives are not subject to FERC's jurisdiction.

[24] *FERC Order 890 Preventing Undue Discrimination and Preference in Transmission Service*, FERC February 16 2007.

transparent, and that FERC itself has the power to resolve disputes between transmission service providers and customers over planning (and other matters).[25]

FERC Order 890 reforms and clarifies the rules which set out how transmission providers must set their access tariffs, and the rules on transmission planning. Here we summarise the nine principles which a transmission provider's planning process must satisfy in order to comply with the Order.

Nine Principles of the planning process

1. Co-ordination
   transmission providers must meet with all of their transmission customers and interconnected neighbours to develop a transmission plan on a non-discriminatory basis
2. Openness
   the transmission planning process must be open to all (with appropriate procedures in place to manage confidential information)
3. Transparency
   transmission providers must disclose the basic criteria, assumptions, and data that underlie their transmission system plans
4. Information exchange
   transmission customers are required to provide information on their demand for transmission services on a comparable basis to the transmission service provider's planning approach
5. Comparability
   the transmission provider must plan its system so that equivalent customers are treated comparably—this includes a requirement to treat services provided by demand customers comparably with services provided by generators
6. Dispute resolution
   the transmission provider must develop a dispute resolution process which would be available to customers with either procedural or substantive complaints
7. Regional participation
   transmission providers are required to coordinate with interconnected systems to (1) share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data and (2) identify system enhancements that could relieve congestion or integrate new resources
8. Economic planning studies
   the planning process must include studying upgrades that could relieve significant and recurring congestion, as well as upgrades to connect new generation or loads on an aggregated or regional basis: "planning involves both reliability and economic considerations"
9. Cost allocation for new projects
   transmission providers must propose a cost allocation method for projects not funded by existing mechanisms (ie, associated with connection requests), for example regional projects involving several transmission owners or economic upgrades; there are no prescribed rules, but when considering a dispute over cost allocation, FERC will take into account fairness in assigning costs among participants, including those who cause them to be incurred and those who otherwise benefit from them, the need for adequate incentives to construct new transmission, and whether the proposal is supported by stakeholders

As noted above, one of the roles of an RTO is to "have ultimate responsibility for both transmission planning and expansion". This requires both a direct hand in planning and co-ordination of the transmission planning process among its constituent TOs and other stakeholders. The US has had limited experience with regional transmission planning (apart from the voluntary coordination for major new lines that occurred in the past), given that ISO/RTOs are relatively new organisations (e.g., CAISO was established in 1998, PJM in 1997). However, the regulatory rules on transmission planning are evolving,[26] and the role of ISOs/RTOs in the planning process

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[25] See discussion at paragraphs 567–568 of Order 890.

[26] FERC Order 890 of February 2007 made some significant changes.

is growing.[27] Initially, the ISO's "planning" consisted of little more than compiling the investment plans of its constituent TOs.[28] Once the ISO/RTO was established, it typically worked in tandem with TOs to identify and evaluate projects needed to maintain reliability and to interconnect new generators to the transmission network. Only more recently have ISOs/RTOs begun to identify and perform cost/benefit studies of investments designed to reduce congestion costs, facilitate trading, and enhance the competitiveness of regional power markets. The latter are referred to as "economic" (i.e., primarily economically-justified) transmission investments, as opposed "reliability" investment (i.e., primarily needed to meet reliability standards).

California

The CAISO provides an example of the changing role of the ISO in the transmission planning process. Before 2006 the process began with TOs submitting 10 year investment plans for CAISO review (CAISO checked that the projects were needed to address a specific problem, and were the best solution to that problem). CAISO combined the TO plans, and checked for consistency. Thus the CAISO role was reactionary—it did not make any investment proposals itself—and decisions such as trading off transmission and generation investment were left to the TOs (subject to regulatory approval).[29] Under the new process, which is being run for the first time in 2007, CAISO will itself identify investments which need to be made, and the TOs will react to CAISO proposals.

In addition to input from and collaboration with TOs, the California planning process also involves the California Energy Commission (CEC) and the California Public Utilities Commission (CPUC), as well as other bodies. The CEC is the state energy policy and planning agency, and its main role in the CAISO planning process is to produce load forecasts and approve generation siting requests. The CPUC, however, is responsible for siting and approval for transmission projects. The overall process is illustrated in Figure 5.[30] It is inevitably complex, reflecting the number of institutions involved.

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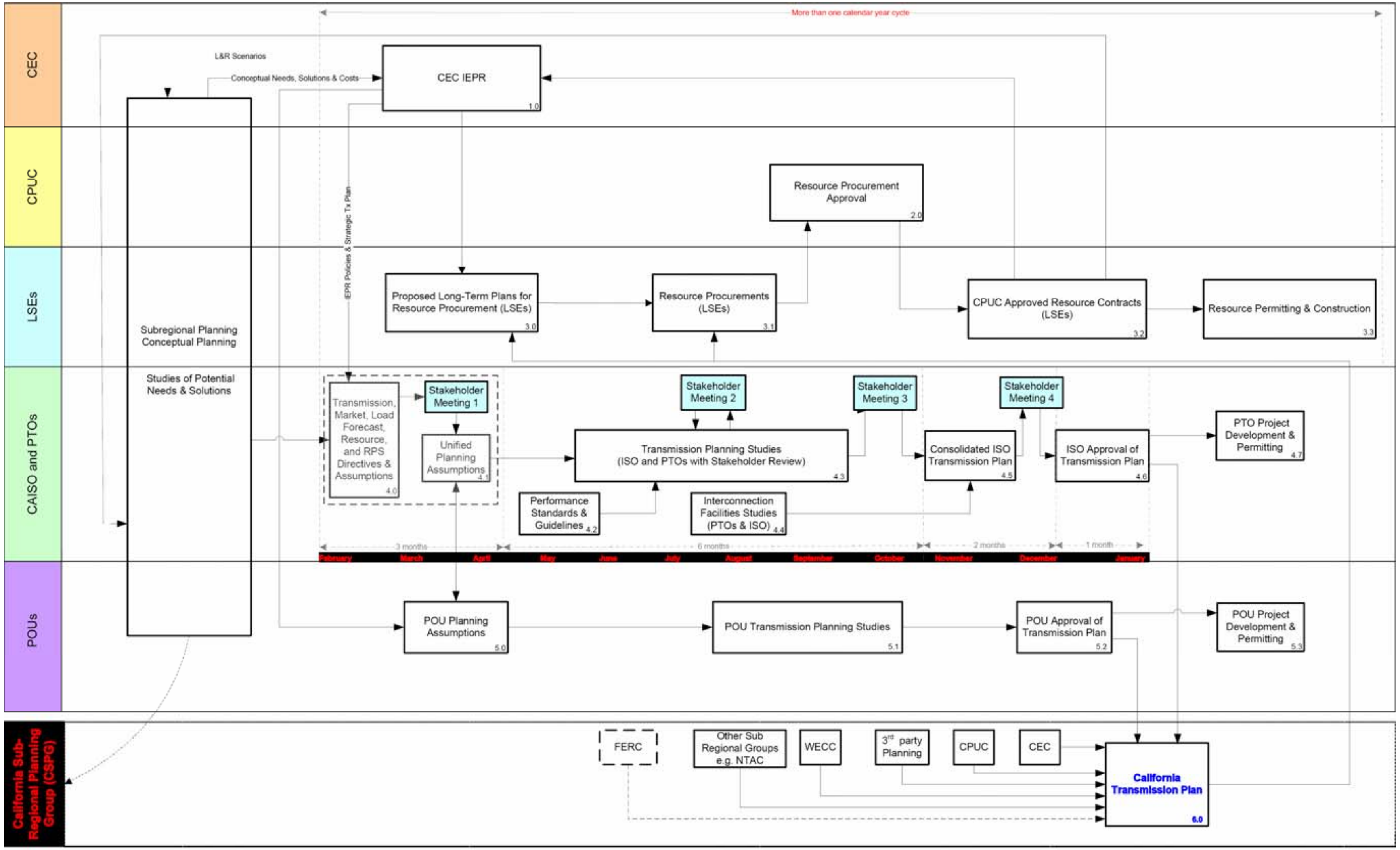
[27] See, for example, FERC-sponsored developments at http://www.ferc.gov/industries/electric/indus-act/oatt-reform/draft-attachment-k.asp. The WECC regional grouping has developed a transmission planning process to support transmission providers in meeting their transmission planning obligations flowing from Order 890: *TEPPC Planning Protocol Draft Version 1-3*, WECC 2007.

[28] See *ISO/RTO Electric System Planning: Current Practices, Expansion Plans and Planning Issues*, ISO/RTO Council Planning Committee, 2006.

[29] *ISO/RTO Electric System Planning: Current Practices, Expansion Plans and Planning Issues*, ISO/RTO Council Planning Committee, 2006, discussion at p. 89.

[30] Taken from *2007 Transmission Plan*, CAISO 2007. LSEs are "Load Serving Entities", PTOs are "Participating Transmission Owners", and POUs are "Publicly-Owned Utilities".

Figure 5: CAISO Planning Process



* By responsible entities and timeframe associated with each process that could fit in a single calendar year or more

- - - - A Possible Process

CAISO/PG&E/SCE/SDG&E
8/15/2006 Ver 16

On the basis of the CAISO transmission plan, TOs make investment proposals to the California Public Utilities Commission (CPUC). The CPUC review process includes evaluation of alternatives to transmission investment or projects which allow deferral of transmission investment.[31]

Other RTOs/ISOs

In respect of regional planning and co-ordination, an important difference between CAISO and, for example, PJM and MISO[32] is that CAISO covers one, albeit large, state and PJM and MISO cover several. CAISO has experienced difficulties in co-ordinating with neighbouring jurisdictions for regional planning (e.g., the refusal of the Arizona authorities to allow upgrade of interconnection, described below), whereas the PJM and MISO control areas themselves have more of a regional nature. However, the CAISO planning process seems to be better developed, especially in respect of "economic" expansion, than those used in PJM and MISO.

Alberta

The most recent AESO 10-year transmission plan[33] provides a useful summary of the Alberta planning process:

> *There is a routine cycle of transmission system planning that has been established in Alberta:*
>
> - *Every four years the 20-Year Transmission System Outlook lays out the long-term strategic direction for the transmission system and transmission interconnections;*
> - *Every two years the 10-Year Transmission System Plan provides greater detail of the projects required to meet the most likely scenario(s) of load and generation development; and*
> - *On a continuing basis detailed plans are developed as part of the Need Application process.*
>
> *This planning cycle allows plans to flow from the broad outlines of future needs to the very specific equipment necessary to provide interconnection of new load and generation and maintain system reliability.*

This planning cycle is laid down in Albertan legislation, which describes in some detail the 20 year outlook, 10 year plan, and "needs identification" documents. The 20 year outlook is a "long term transmission system outlook document" that projects over at least twenty years the forecast load, generation capacity required to meet the load (with timing and location), and the transmission capacity needed to meet these forecasts and also allow for "efficient and reliable

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[31] *2007 California ISO Transmission Plan*, CAISO 2007.

[32] MISO is the Mid-west ISO.

[33] *10-year Transmission System Plan 2007–2016*, AESO 2007.

access to jurisdictions outside Alberta".[34] The 10 year plan is required to cover similar ground but in greater detail, and to be updated at least every two years.[35] Concrete proposals for investments are then covered by a "needs identification" document that the AESO submits for regulatory approval:[36]

> *When the Independent System Operator determines that an expansion or enhancement of the capability of the transmission system is required to meet the needs of market participants, the Independent System Operator must prepare and submit to the Board for approval a needs identification document that*
>
> *(a) describes the constraint or condition affecting the operation or performance of the transmission system and indicates the means by which or the manner in which the constraint or condition could be alleviated,*
>
> *(b) describes a need for improved efficiency of the transmission system, including means to reduce losses on the interconnected electric system, or*
>
> *(c) describes a need to respond to requests for system access service.*

As in other parts of North America, the planning process led by the AESO involves extensive stakeholder consultation.

2.2.2 Implementation and transmission cost recovery

Typically the transmission plan is implemented by TOs bringing forward investment proposals to state regulators (siting) and FERC (revenue requirement), in order to deliver the transmission upgrades in the plan. This is how the CAISO transmission plan will be implemented, with constituent TOs undertaking the necessary investment projects, subject to regulatory approval (from the CPUC). TOs can propose alternatives to CAISO plans, and if TOs refuse to carry out a CAISO proposal a mechanism will be developed for third parties to carry out the work, following competitive tender.

In Alberta the AESO has significant powers to direct investment. Once the regulator has approved a "needs identification" application, the relevant legislation provides that AESO can require a TO to submit an upgrade proposal for approval by the regulator (the owner can propose a non-transmission solution instead, and the AESO decides whether this is acceptable). The CAISO arrangements are similar: if a TO declines to accept a CAISO investment proposal or to propose an acceptable alternative, CAISO may itself tender for the work to be done. In the CAISO case these arrangements are not yet fully developed.

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[34] Electric Utilities Act, Transmission Regulation AR 86/2007, section 9.

[35] *Ibid*, section 10.

[36] Electric Utilities Act 34(1).

Cost recovery

Costs associated with transmission plans that are implemented are recovered through the investment being added to the TO ratebase, and cost recovery being determined through the tariffs, which must be approved by the relevant regulatory authority. A key issue for implementation is whether the revenues that allow cost recovery must be collected from the investor's own connected customers, or whether other users of the larger interconnected system can also be charged. In the US this distinction is referred to as "licence-plate" vs "postage-stamp" approach to transmission pricing. RTO-set transmission rates typically vary by transmission zone, with zones generally being defined as the service area of a transmission-owning utility (hence "licence plate"). Since RTOs are comprised of multiple TOs, with potentially very different average costs (reflecting past investment), the licence-plate approach can result in charges which vary widely by zone. However, in some regions there is an evolution toward a postage-stamp approach, with uniform tariffs across an ISO/RTO region. For example, California implemented postage-stamp treatment for all new high voltage transmission investments (200 kV and above) in 2001, along with a 10-year transition to a postage-stamp system its existing high-voltage lines. This regional postage-stamp cost recovery treatment has been justified with the rationale that all high-voltage transmission above 200 kV has broad regional benefits.

Order 890 does not specify precise rules for how the costs of transmission investment should be recovered from users. However, it does set out three factors that FERC will consider in deciding on cost allocation for projects involving several TOs or "economic" investment projects:

- FERC will consider the extent to which charging proposals are "fair" in so far as they allocate costs to the users that cause them and the users which benefit from investment;
- it will consider whether the charging proposals give adequate incentive to construct new capacity; and
- it will take into account whether or not proposals have the support of state regulators and other stakeholders.

In its decisions on individual transmission tariffs, FERC has encouraged a move towards postage-stamp charging (for example, it was mandated in a recent order concerning PJM charges for extra high voltage assets).[37]

The Alberta system also has a strong preference for postage-stamp tariffs, having adopted a fundamental principle that "pricing and payment for transmission is fundamentally a cost most appropriately borne by the loads that are served by the transmission system on an equal basis, regardless of location".[38] New generators are required to assume some costs for transmission upgrades ("generator contribution") but this is essentially a guarantee against asset stranding, and is refunded over ten years provided the generator makes use of the assets.

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[37] 119 FERC ¶ 61,063, April 2007.

[38] *Transmission Development, The Right Path for Alberta: A Policy Paper*, November 2003.

2.2.3 Responding to market needs

As in other systems, transmission planners use a variety of tools to assess market needs. These will include "top-down" forecasts based on assessments of load growth, changes in generation etc, and "bottom-up" forecasts based on aggregating input from individual TOs. For example, as described above, the Alberta ISO is obliged to publish and file with its regulator both a "twenty year outlook" that uses a top-down approach to provide a background to transmission planning, and a transmission plan with a ten year horizon, which makes use of a more detailed ten year forecast (the "ten year generation outlook").

Transmission planners in US LMP-based markets also make use of the market signals provided by LMP, which can be a valuable tool for highlighting the existence and extent of congestion at different points in the system.

Incentives to respond to market need include both legal obligations and financial incentives. As a matter of law, there is an obligation to connect new generation that is willing to pay the (usually "deep", i.e., system-wide) connection costs, and as discussed above, an obligation to perform economic assessments.

FERC's Order 890 requires planning studies to examine not only upgrades identified by applying technical engineering criteria ("reliability" investments) but also "economic" upgrades. The main focus seems to be on investment that would reduce congestion costs, but Order 890 also requires transmission service providers to study the potential benefits from other upgrades if requested by users or potential users. For example, it might be the case that expansion of the main grid into remote areas would allow renewable energy resources to connect to the grid. Since there are typically many small renewable generators which together can add to a significant quantity of capacity, and since network expansion is typically "lumpy", it is possible that an expanded network would (eventually) be fully utilised and recover its costs from normal access charges. However, neither such expansion nor even a study of the costs of such expansion would have been triggered by a connection request from any individual generator, because each individual generator is too small to pay for the transmission project. Order 890 requires such studies to be undertaken, though it does not specify how the costs of expansion should be paid for.

CAISO is developing a process to identify grid expansion to remote areas in order to facilitate the development of significant renewables resources. The mechanism involves a market test to demonstrate interest from potential renewable developers, as well as firm connection requests for a proportion of the capacity, but once that test is passed CAISO will be able to invest in expanding the grid, with the cost of the expansion initially funded out of general system revenues. Once generators start connecting to the grid, they will start paying access fees in the normal way. The mechanism is under development and awaiting final approval, but could lead to significant investments.[39] CAISO has already made outline plans to build new transmission links to the Tehachapi area with over 4,000 MW of wind generation potential (projected cost is around $1.8 billion).

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[39] See, for example, *California ISO Near-Final Proposal for Location Constrained Resource Interconnection*, CAISO September 2000.

Financially speaking, regulation means that the incentive to invest depends on the allowed rate of return, as well as perceptions of the level of regulatory risk. Partly as a result of the 2000–2001 California crisis and the North-eastern blackout of 2003, the Energy Policy Act 2005 requires FERC to offer "incentive-based rates" for transmission investment. The basic approach is to set rates of return at the upper end of the "zone of reasonableness" as assessed under FERC's standard approach. In one recent decision on investment in the ISO-New England region FERC granted a 1% premium as the incentive component of the return.[40] The incentive rates are available to all major new transmission investment, but investors need to show why the incentives are "needed" to allow the investment to go ahead (although in practice this test may not be too difficult to meet—FERC has ruled that investors do not have to show that, "but for" the incentives, the investment would not happen). FERC's incentives policy also allows: full recovery of prudently-incurred construction work in progress, pre-operations costs, and stranded costs; use of hypothetical capital structures; accumulated deferred income taxes, and adjustments to book value, in transactions for transmission companies; accelerated depreciation; deferred cost-recovery for utilities with retail rate freezes; and a higher return on equity for members of ISOs/RTOs.[41] The incentives seem to be a response to past under-investment, and may therefore be better seen as an inducement to bring forward new investment quickly than as compensation for new types of risk, or risk that was previously not properly identified.

One of the design objectives of the LMP system was to allow merchant transmission links to be built in response to price signals. In fact, until recently, some ISOs/RTOs resisted planning "economic" upgrades on the grounds that a market outcome would be more efficient. Proponents of "market-driven" transmission investment argue that revenues from LMP differences and financial transmission rights[42] would be sufficient to fund economic investment. In practice, almost all of the initially-proposed merchant interconnector projects have subsequently been cancelled, and it is now generally felt that merchant investment in transmission is unlikely to be significant.[43] However, while LMP differentials may not cause entry of merchant transmission projects, they frequently highlight the need for "economic" transmission projects that are planned and whose costs are recovered under the traditional regulatory framework.

The debate in Alberta that led to the current system for transmission planning also saw scepticism about the use of market signals. A key policy paper asserted that "[i]t is not reasonable

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[40] Opinion 480, 117 FERC 61,129, October 2006.

[41] See Order 679, 116 FERC ¶ 61,057, July 2006, and http://www.ferc.gov/industries/electric/indus-act/trans-invest.asp.

[42] A system of financial transmission rights means that, for example, a generator that pays for some system reinforcement triggered by its connection to the system will be assigned financially firm rights over the capacity it has paid for. The generator would thus receive any future congestion revenues associated with that capacity. In principle, merchant transmission investment within an existing grid becomes possible with a system of financial transmission rights.

[43] For example, see comments in *Regional Transmission Expansion Plan 2006*, PJM at p. 29.

to expect that market signals, congestion pricing schemes or similar methods will result in timely construction of transmission facilities or assure their sufficiency to meet system needs".[44]

2.2.4 Trading off transmission and non-transmission investments

As in any system, the trade-off between transmission and non-transmission investments can be addressed through a cost–benefit assessment, market signals (e.g., locational pricing), or a combination of the two. Both approaches are used, to varying extents, in North America.

Economic assessments will typically compare transmission projects against alternative solutions which do not require network investment, including demand-side measures. FERC Order 890 requires that the planning process allow customers with price-responsive demand to participate where these customers are capable of providing resources that would be useful to the SO. Demand reductions provided by price-responsive customers must be treated on a comparable basis to equivalent services provided in other ways. PJM and ISO-New England are in the process of adapting their planning processes to allow customers to participate.

As mentioned earlier, RTO or ISO-based electricity markets in the US typically use LMP. In principle, LMP signals to potential investors the value of building new generation at various points on the network, because prices will be high at nodes where there is insufficient network capacity to import cheaper electricity from other locations. LMP can also signal the need for new transmission capacity: the price difference between adjacent nodes is a measure of the value of building new capacity between those nodes.

In practice, however, it seems unlikely that LMP alone is sufficient to foster efficient levels of investment in new generation and transmission capacity. For example, transmission investment could be triggered by reliability standards even when LMP price differences are insufficient to support investment in new network capacity (or in new generation in a load pocket). Thus LMP signals seen by generators would be muted: investment in generation might not be triggered by high LMP prices if investors feared that subsequent transmission investment would lower them again. Alternatively, difficulties in obtaining planning permission for new transmission investment could push the trade-off in the other direction: generation capacity might be built in response to high LMP prices even though it would be cheaper to build network capacity instead. LMP prices are difficult to predict, and it is difficult to predict the impact on prices of new investment (in both generation and network capacity).[45]

A better view of LMP is probably that it is effective at short-term congestion management as well as at making the existence of congestion transparent both to potential investors and to regulators. For example, PJM identifies all of its assets which cause constraint costs above set thresholds, and identifies the costs and benefits of upgrades to relieve the constraints.[46] Upgrades

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[44] *Transmission Development, The Right Path for Alberta: A Policy Paper*, November 2003.

[45] See discussion in *Patterns of Transmission Investment*, Paul Joskow, MIT 2005 at p. 45.

[46] The procedure for identifying constraints is set out in *Business Rules for Economic Planning Process*, PJM 2007.

which pass the cost–benefit test are recommended for inclusion in the PJM Regional Expansion Plan. An interesting feature of the PJM system[47] is that TOs and market participants can (or will be able to—the PJM planning process is currently evolving)[48] propose alternative investments to deal with any of the constraints which PJM plans to upgrade. In principle, for example, this would allow a developer to propose a new power station instead of transmission upgrade.[49] However, there is no mechanism that could explicitly pay the developer part of the saving it created in transmission investment, although the fact that connection charges are "deep" provides an incentive to locate on the load side of transmission constraints. Thus while the planning process does envision that alternatives to transmission investment should be considered where these would be cheaper, in practice if generation resources are used to avoid network investment this tends to arise as a result of factors that re not strictly part of transmission planning (e.g., generation may be built in response to incentives intended to help ensure generation adequacy requirements are met).

2.3 "Reliability" and "economic" investments

There has been extensive discussion in the US of the distinction between:

- "reliability" investments—those identified as the result of applying technical engineering standards (reliability criteria) to a defined model of flows on the network; and
- "economic" investments—projects which have not been identified as being necessary to meet technical reliability standards (developed and enforced through NERC), but which are identified as passing some kind of economic test—for example, an upgrade which would relieve congestion and where the cost of the upgrade is less than the expected savings in congestion management.

In many cases an investment may necessary for both economic and reliability reasons (or a combination of the two—for example, a project might be put into a 10-year system plan for reliability reasons in year 7, and then economic analysis might move the ISO/RTO to bring forward the investment to year 5). Historically, however, TOs have whenever possible sought regulatory approval on the basis that their proposal is required for reliability, even if in theory they could have made a solid economic argument. For example, between 1999 and 2005 grid

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[47] Described in Schedule 6 of the *Operating Agreement of PJM Interconnection LLC*, http://www.pjm.com/documents/downloads/agreements/oa.pdf.

[48] See http://www.pjm.com/planning/epis.html.

[49] "The process of formally submitting proposals is not limited to transmission solutions but may also include generation solutions via PJM's established interconnection queue process; or, demand side management and load management proposals as well." *Regional Planning Process Working Group: Market Efficiency Analysis White Paper – Transmission Expansion Advisory Committee (TEAC)*, PJM 2007.

expansion in the PJM system cut congestion costs by over $200m, but 90% of the reduction came from investments identified for "reliability" reasons and only 10% from "economic upgrades".[50]

The bias reflects the reality of regulatory practice: state utility commissions have typically been happy to approve reliability upgrades, but have been less inclined to approve proposals for economic upgrades, particularly if the proposed upgrade primarily benefits out-of-state customers. One reason for this bias is the strong nexus between reliability and the public interest—one of the foremost objectives of regulators is to provide safe and reliable electricity service. Few residents welcome a transmission line on or near their property, but overcoming public opposition to a new line is somewhat easier if the case is made that the line is needed to continue the provision of reliable supply, as no one wants unreliable service either. In addition, transmission system operation and engineering is a complex subject, and regulators are more inclined to approve investments when a new line is needed to meet the (now mandatory) reliability criteria. While stakeholders may well question the need for a proposed line, they often lack the resources or technical expertise to question the utility's or regional planning group's contention that a line is needed for reliability. Furthermore, it is easier to see that reliability upgrades benefit local customers—who are often the ones paying for the investment—whereas economic upgrades may raise difficult distributional issues (e.g., when a new line facilitates regional trade that may not directly benefit local customers). It is always possible to "push the congestion to the border" by reducing capacity at interconnections between regions in order to avoid inter-regional flows triggering reliability issues. Finally, there is always a political risk in rejecting a reliability proposal, since any bad outcome in the future (e.g., a brownout/blackout) could be blamed on the rejection.

2.3.1 "Reliability" investments

US electricity industry reliability requirements are incorporated in the reliability standards that have been established by the NERC and its associated Regional Reliability Councils. NERC monitors compliance with the standards and publishes the results in its quarterly and annual reports.[51] NERC is also authorised to impose sanctions on the violators, for example, "penalties for standards violations include sanctions that impose limitations or restrictions on activities; remedial action directives designed to correct conditions, practices or other actions posing a threat to reliability; and fines of $1,000 to $1 million per day."[52,53]

The reliability standards provide details on how different parts of the system should operate but not on how the system should be designed. "Individual owners, operators and users of the bulk power system determine if the system should be expanded or changed, and how, in order to

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[50] *The Value of Independent Regional Grid Operators*, ISO/RTO Council, 2005.

[51] *Compliance Monitoring and Enforcement Program Report*, available at http://www.nerc.com/~comply/quarterly.html.

[52] *Background NERC Reliability Standards* p. 2, 2007.

[53] Further details on compliance and sanctions are available from *Appendix 4B. Sanction Guidelines of the North American Electric Reliability Corporation,* June 7, 2007.

achieve the standards."[54] The performance of the system is defined under various conditions: normal operation, following loss of either a single element, two or more elements, or in case of extreme events. Selected characteristics of each system category are presented in Table 2.

Table 2: Selected Characteristics of Various System Categories[55]

Category	Example of Contingency Elements	System Limits or Impacts: System Stable and both Thermal and Voltage Limits within Applicable Rating[1]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in service	Yes	No	No
B Loss of single element	Single Line Ground (SLG) or 3-Phase Fault; Loss of element without a fault	Yes	No	No
C Loss of two or more elements	SLG Fault with normal clearing[2]	Yes	Planned/ Controlled	No
D Extreme events resulting in two or more elements removed	3-Phase Fault with Delayed Clearing	May involve substantial loss of customer demand and generation in a widespread area		

[1] Applicable Rating is determined individually for each operator according to the approved methodology.

[2] Normal clearing is usually defined as 30 min or less.

The Alberta system follows the NERC/WECC reliability standards, as do the provinces of Ontario and New Brunswick.

As in most other systems we have examined, reliability standards are a legacy, set by engineers without any underlying economic calculations. There is little debate in North America about changing the methodology for setting standards towards a more economics-based approach (or integrating reliability and economic assessments into a single approach).

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[54] *Background NERC Reliability Standards* p. 2, 2007.

[55] Table adapted from *Regulations TPL-001* to *TPL-004*, NERC 2007, available on http://www.nerc.com/~filez/standards/Reliability_Standards_Regulatory_Approved.html.

2.3.2 *"Economic" investments*

Most ISOs/RTOs—often with prodding from FERC—have added a mechanism to identify economic transmission upgrades in addition to upgrades needed for "reliability" reasons. This requirement has been codified under FERC Order 890, which now requires transmission planners to have a process to identify economic projects. The details of the tests used to identify economic investments vary across ISOs/RTOs—the results of a survey of current practice just before Order 890 was finalised are summarised in Table 3. In response to Order 890 some ISOs/RTOs are adapting their methodologies. For example, PJM now looks at a range of forward-looking estimates of the impact on congestion.[56]

Table 3: ISO/RTO approaches to economic planning

ISO/RTO	Responsibility	Process	Measure of benefits
CAISO	ISO plays an important role	ISO developed detailed economic assessment methodology involving stakeholders and regulators	Various, including societal and CAISO participant benefits
ISO-NE	ISO	ISO provides information; stakeholders advise on need for upgrades	Production costs and losses
PJM	ISO	Provides information; plans upgrade if market solution not forthcoming within 12 months	Congestion savings
NYISO	Market participants	Provides information to market participants	Production costs
ERCOT	ISO lead	ISO leads annual reviews	Production costs
Ontario	Market	Provides information to market participants	None defined
Alberta	ISO	Economic and reliability considerations taken together in the planning process	None defined
SW Power Pool	ISO	Part of the planning process	Production costs
Midwest ISO	Market	Provides information to market participants; ISO may develop solutions	Various, including production costs, marginal load payment, generator revenues

Notes
This table is adapted from Table 2 in ISO/RTO Council Planning Committee Phase I Transmission Planning Report, October 2006.
Since the publication of that report FERC Order 890 has made economic planning a mandatory element of ISO transmission planning.

Cost–benefit assessments

A significant barrier against getting proposals made and approved for economic upgrades has been the narrow approach used in assessing economic benefits. The "default" methodology used by US RTOs such as PJM and the Midwest ISO focuses only on savings in generation costs. However, transmission upgrades can also give rise to many other benefits, notably enhanced competition. (As we discuss elsewhere in this report, it is the desire for enhanced competition that drives continental European efforts to get increased interconnection between national markets.)

[56] See, for example, 119 FERC ¶ 61,265, June 2007.

The Western Power Crisis of 2000–2001 has given rise to a growing recognition that the traditional cost–benefit methodologies under-estimate the true returns to transmission investments. A 2003 report commissioned as part of the response to that crisis argued that:[57]

> *The real societal benefit from adding transmission capacity come in the form of enhanced reliability, reduced market power, decreases in system capital and variable operating costs and changes in total demand. The benefits associated with reliability, capital costs, market power and demand are not included in this [type of production cost] analysis.*

In some cases transmission planning methodologies are evolving to factor in some of these additional benefits, even though some of the benefit categories are not easily measured. For example, network expansion might improve competition by reducing the number of hours when constraints cause regional markets to split into smaller areas with location-specific prices. The increase in competition will bring economic benefits, but these are hard to measure, and thus give scope for disagreement between (for example) customer groups and incumbent generators. The benefits of increased competition are explicitly included in the CAISO's "TEAM" process (described in the following subsection), but they are extremely uncertain. For example, the competitiveness benefits of two upgrades assessed by CAISO averaged 50–100% of the direct production cost savings, but with a range of 5% to 500%, depending on future market conditions (gas prices, demand evolution, and the availability of hydro resources).[58]

CAISO

The CAISO has developed a detailed methodology for evaluating economic grid upgrades, the "Transmission Economic Assessment Methodology" (TEAM). Some key features of the methodology are as follows.

- It recognises and quantifies a number of benefits other than reduced production cost. Figure 1 in the introduction to this report showed the breakdown of a TEAM benefits analysis for one potential upgrade, which included not only production savings but also increased competition, operational benefits, reductions in needed generation investment, and reductions in transmission losses and in emissions. The effect was to more than double the estimated benefits relative to a traditional analysis.
- It recognises that a cost–benefit assessment can be applied from different perspectives. For example, total social benefits and costs can be estimated, or the assessment can be limited to a consumer (regulated rate-payer) perspective, or it can be limited in geographic scope. In assessing changes in market power, the assessment can regard any reduction in monopoly rents as a "pure benefit", or it can take into

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[57] "*Framework for Expansion of the Western Interconnection Transmission System*", Seams Steering Group – Western Interconnection (SSG-WI), Oct 2003.

[58] Discussed in *Evaluating the Economic Benefits of Transmission Investments*, by Johannes P. Pfeifenberger and Samuel A. Newell of *The Brattle Group*, presentation at EUCI's Cost-Effective Transmission Technology Conference, Nashville, TN, May 3rd 2007.

account the net benefit (i.e., producers generally lose from increased competition, but consumers' gains outweigh the producers' losses).

- It uses a robust model of physical flows on the network. CAISO analysis showed that having a good model of flows is essential: it reviewed an investment proposal that had been made on the basis of a contract path analysis, and came to an opposite conclusion on the project when it used a physical flow model.
- It explicitly considers risk and uncertainty: the outcome of the assessment may depend on factors such as future fossil fuel prices, but it may also be important to take into account unlikely but extreme scenarios. For example, network investment that connects two regions and is just economic in normal years may turn out to be extremely valuable in a year where one of the regions suffers a shortage of generation capacity. The methodology envisions detailed scenario analysis, with probabilities being assigned to scenarios in order to make "most likely" estimates of benefits.
- A particular difficulty in transmission planning is over whether to take into account only those new generation projects which have already progressed some way through the permitting process, or whether to make a more general assessment of where new capacity might connect. The TEAM methodology recognises that it usually takes a lot longer to plan and obtain permits for transmission than for generation, so it recommends that the transmission planning process should include various "what-if" scenarios for new generation, and thereby influence generator future siting decisions, rather than responding to actual connection requests.

Further categories of cost and benefit that could be taken into account

Even the CAISO methodology still leaves out many benefits that could be factored into a cost–benefit assessment, albeit many of these are hard to quantify. For example, in recent proceedings before the Arizona PUC, Southern California Edison sought regulatory approval for a new line between California and Arizona and submitted a cost–benefit assessment that used the TEAM methodology. Other testimony submitted in the proceedings argued that even this assessment omitted many potential benefits from the upgrade:[59]

- the economic value of increased reliability;
- economic benefits from construction and taxes;
- greater market liquidity;
- greater fuel and load diversity;
- improved generation investment climate;
- improved resource utilization;

[59] Testimony of Johannes Pfeifenberger (*The Brattle Group*) before the Arizona Power Plant and Transmission Line Siting Committee, August 2006.

- complementarity with other transmission projects; and
- improved access to renewable resources.

The Arizona Power Plant and Transmission Line Siting Committee largely accepted these findings: its conclusions identified over ten benefits of this nature (however, the Arizona Commission itself rejected the proposal, as discussed later).

Alberta

The approach in Alberta is fundamentally different, and is based on a "predict and provide" philosophy. Relevant legislation requires the AESO to "plan a transmission system that is sufficiently robust so that 100% of the time, transmission of all anticipated in-merit electric energy … can occur when all transmission facilities are in service".[60] This reflects an underlying policy decision to construct a transmission system to "serve and facilitate a competitive wholesale market … the transmission system must be relatively congestion free or the underlying market model will not function properly. The ISO must therefore proactively plan transmission development to achieve this result of 'congestion-free' transmission".[61]

2.4 Co-ordination of transmission planning

The fundamental tools for ensuring coordinated planning in the North American system are the regional planning processes administered by RTOs, and the rules embodied in FERC Order 890, both of which have been described above in some detail. These institutions and rules create obligations on TOs to co-operate in transmission planning, and so mitigate—though they cannot remove—the incentives to avoid parochial decision-making. While an RTO cannot oblige participating TOs to co-operate, it makes non-co-operation more apparent and therefore more difficult (politically more costly), and in some cases there are mechanisms available to the RTO to invest directly if a TO refuses. Moreover FERC provides incentives on utilities to join an RTO, in the form of higher allowed rates of return. Finally, from a technical point of view RTOs are better placed than individual TOs to do transmission planning, because they have access to data which the TOs do not have—for example, detailed bid data relevant to the assessment of future market prices and constraint costs.

A further important factor in delivering successful co-ordinated investment in North America is the development of financing mechanisms that allow the costs of transmission upgrades to be shared among users of an ISO/RTO operated network, rather than paid for by the users connected to the particular TO owning the network being upgraded (i.e., the switch from licence-plate to postage-stamp systems described earlier).[62] FERC is promoting further moves towards postage-stamp tariffs. CAISO has recently moved to this system, and some of the recent investment activity is likely to have been facilitated by this move, notably the "Path 15 upgrade" project.

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[60] *Electric Utilities Act, Transmission Regulation AR 86/2007*, section 15.

[61] *Transmission Development, The Right Path for Alberta: A Policy Paper*, November 2003.

[62] Although note that the key point is that the costs are shared, not that they are shared equally.

This project was financed by an independent investor (i.e., not one of the existing TOs, although the project still earns a regulated return), and cost recovery is achieved through charges that apply to the entire CAISO service area.

There is, however, no mechanism in place that allows winners to compensate people who "lose" as a result of a transmission upgrade (e.g., because the upgrade removes the benefit of excess generation capacity in their area), and this can be a significant problem particularly in projects that cross state boundaries and so require approval from multiple state regulators. An example is provided in the dispute over upgrading the interconnection between south California and Arizona (the proceedings discussed in section 2.3.2 above). The investment was approved on the California side but denied on the Arizona side, because Arizona state regulators were worried that the extra capacity would lead to higher wholesale prices into Arizona. While the existing arrangements do allow for payments to be made such that the cost of the transmission upgrades within the Arizona system would have been paid for entirely by customers in California, there is no mechanism to compensate Arizona ratepayers for actual or perceived economic transfers (if any) resulting from the use of the enhanced transmission capacity.

2.5 Evolution

In this section we briefly review the regulatory and other changes discussed above which have had a significant impact on the way that transmission systems are planned.

The push towards ISOs/RTOs is significant for two related reasons: first, it separates transmission asset ownership from transmission system operation, and second it results in transmission systems across a larger geographic area being operated as a single system. Separating the TO and SO functions was important because vertical integration meant that utilities were able to use the transmission planning process to block competition, either from merchant generation, or between neighbouring utilities. Extending the reach of a single SO to the regional scale is important because it internalises boundary problems, and makes co-ordination easier. It also allows transmission charging for economic upgrades to be fairer, and hence less contentious, because transit flows are internalised (see below).

The 2003 blackout in the North-eastern US had a significant economic and political impact. Under-investment in transmission and poor co-ordination among transmission service providers were identified as contributing factors, and the resulting political impetus for change gave rise to amendments to the regulatory framework contained in the Energy Policy Act 2005. For example, reliability standards became mandatory and an enforcement mechanism was implemented, and FERC was given backstop siting powers in certain circumstances. FERC is now able to give attractive rates of return on new investment in transmission assets.

The blackout, as well as the earlier California power crisis, in which underinvestment in transmission was also implicated, have resulted in a change in that state's regulatory environment so far as the approvals process is concerned, probably making transmission investment easier. For example, in California, the assessment methodology applied to proposals for new transmission capacity now takes into account a much broader range of economic benefits, as described above.

The means of allocating the costs of economic upgrades to the regional transmission system is moving from one in which costs were recovered solely from the customers of the utility or utilities that owned the asset to one in which the costs are recovered more broadly from all of the RTO's transmission users. Under the old system, for example, an upgrade to deal with transit flows would be paid for by customers connected to the utility across whose network the transit flows passed, but the parties causing the transit flows would not have been charged at all. Under the new system, the ISO/RTO can charge all users for the new assets.

As a result of FERC Order 890, transmission service providers are required to include an economic assessment of the need for transmission upgrades in their planning process. Prior to this Order, some but not all ISOs/RTOs did this—others considered that price signals would induce efficient levels of merchant investment in new transmission capacity. For example, the PJM system of opening a market window for one year to allow merchant investment in identified "economic" transmission projects is apparently the result of strong FERC pressure, in the face of resistance from PJM, for the ISO to undertake economic investment planning. PJM's original intention had been that a proper system of LMPs and financial transmission rights would induce market participants and merchant investors to find economic transmission investments. The first round of economic investments identified by PJM included some with pay-back periods of less than one year, suggesting either that FERC was right to insist that PJM undertake the work, or that PJM's assumptions were not shared by market participants.[63]

[63] See discussion in *Patterns of Transmission Investment*, Paul Joskow, MIT 2005 (http://econ-www.mit.edu/files/1174) at p. 41.

3 The Nordic Region

3.1 Background

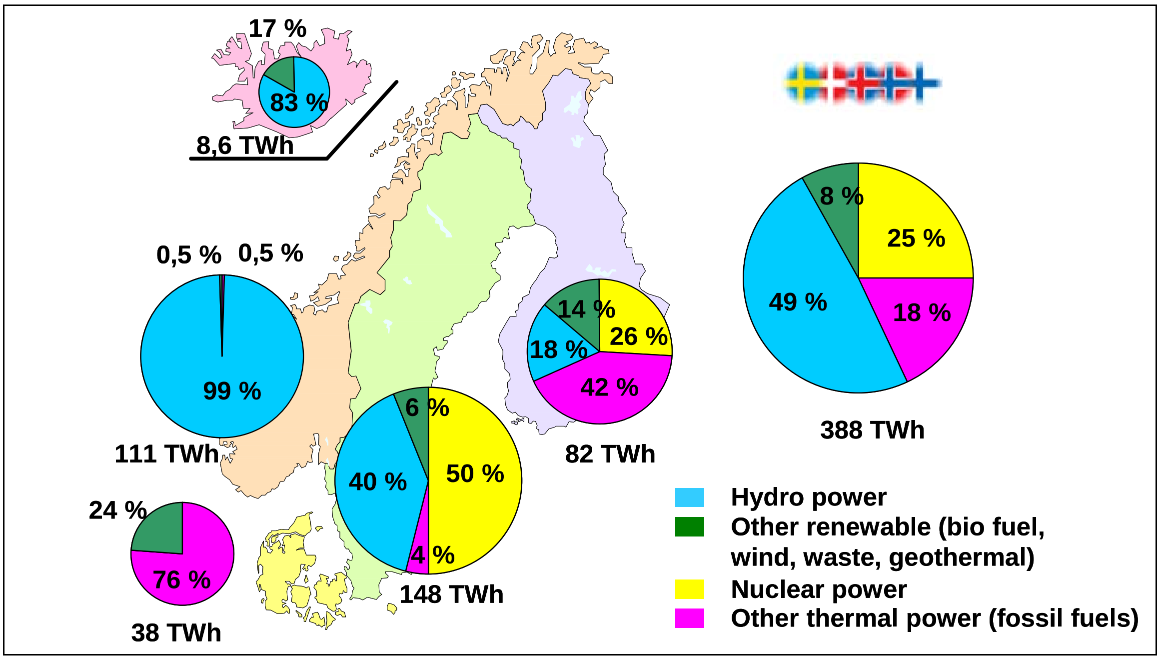
Nordpool is a multinational exchange for trading electricity in Norway, Sweden, Denmark and Finland. It began as a mechanism for promoting competition in Norway in 1993, and was expanded following inter-governmental agreement on co-operation in 1995. Sweden joined in 1996, Finland in 1998, and Denmark in 1999–2000.[64] The Nordpool trading markets (Elspot and Elbas) have recently expanded to quote prices in Germany.

However, "Nordpool" is also commonly used to refer more generally to the common set of trading and transmission arrangements for the Nordic region (the "Nordpool area"). The Nordpool area is interconnected with neighbouring countries through DC links, but Nordpool itself operates as a single synchronised system, with the exception of the West Denmark area, which is synchronised with the UCTE system that covers most of continental Europe. Nordpool operates as a voluntary pool for trading electricity across the four member countries. There are a number of persistent transmission constraints within the Nordpool area which are resolved by "market splitting'—i.e., prices in the different areas can diverge.

As Figure 6 shows, a particular feature of the Nordpool area is that generation in Norway is almost entirely hydro-electric, whereas in Denmark generation is mostly thermal, in Sweden it is nuclear and thermal, and in Finland it is nuclear and hydro-electric. The amount of water available for generating electricity varies considerably from year to year according to the amount of precipitation and the temperature. Thus there can be large flows of electricity between countries, the direction determined by the amount of water inflow to reservoirs in Norway and Finland.

[64] *Steps for improved congestion management and cost allocation for transit*, Norden 2007 (report commissioned from Energy Analyses and COWI).

Figure 6: Power Generation in Nordic Region (2004)[65]



Because of the relative maturity of the Nordpool market area, and what is generally regarded as its success in integrating national markets to mutual benefit, there is a strong focus among TSOs and other stakeholders on further integration of a "Nordic" market, such as investments to relieve constraints between price areas.

3.1.1 Industry structure

Each of the countries in Nordpool has a national transmission system (majority) owned and operated by a single company. The TSOs in Norway (Statnett), Sweden (Svenska Kraftnät) and Denmark (Energinet.dk) are state owned, and the Finish state has a minority stake in the Finish TSO (Fingrid Oyj). Two large conglomerates TVO and Fortum (which also own the main generation companies in Finland) each own 25% of Fingrid, and insurance companies own the rest.[66] Nordpool itself, the operator of the Nordic power exchanges, is owned by the TSOs. In Norway part of the transmission network is owned by municipalities and private companies, but the entire system is operated by Statnett.

The TSOs in the Nordpool region co-operate on a voluntary basis through an association created for that purpose, Nordel. Nordel's mission is to "promote the establishment of a seamless Nordic electricity market as an integrated part of the North-west European electricity market and

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[65] *Development of Interconnection in the Nordic Countries*, Timo Toivonen, President & CEO, Fingrid Oyj, January 2006.

[66] Fingrid website.

to maintain a high level of security in the Nordic power system". [67] To that end it has the following objectives: [68]

- development of an adequate and robust transmission system aiming at few large price areas;
- seamless co-operation in the management of the daily system operations to maintain security of supply and to use resources efficiently across borders;
- efficient functioning of the North-west European electricity market, with the aim of creating larger and more liquid markets, and improving transparency of TSO operations; and
- establishment of a European benchmark for transparency of TSO information.

Nordel publishes forecasts (e.g., of demand), reports on issues such as congestion management, and it has a role in identifying investment needs.

Both wholesale and retail markets are deregulated. Nordpool is often described as a highly competitive wholesale market,[69] and on a regional level ownership of generation is not concentrated. However, the existence of transmission constraints (as well as cross-ownership among generators) has led competition authorities to be concerned about market power. For example, a 2003 study[70] by the Nordic competition authorities expressed concerns about the structure of the market, and recommended increases in transmission capacity between price areas. The study found that while Nordpool as a whole was not concentrated, smaller price areas are.

Table 4: Concentration indices in Nordpool

Market	HHI
Nordic region	1,138
Sweden	3,169
Finland	3,005
Norway	3,644
Denmark	4,844

Notes
Figures from *A Powerful Competition Policy*, Nordic competition authorities 2003.

[67] www.nordel.org.

[68] *Ibid*.

[69] For example, *Nordpool: A Power Market without Market Power*, Erik Hjalmarsson, Working Papers in Economics no 28, Göteborg University 2000.

[70] *A Powerful Competition Policy*, Nordic competition authorities, 2003.

3.1.2 Regulation

Regulatory framework

Each of the four Nordpool countries has its own regulatory authority, and the four regulators co-operate through NordREG. NordREG's aims include "to promote the development of efficient electricity markets in the Nordic area" and "to co-operate in order to promote a competitive Nordic market in electricity, in which the principles of transparency and non-discrimination are ensured.'[71]

The main principles underlying network regulation in the Nordpool region seem to be that access to the networks should be non-discriminatory, and that the network tariffs should be "reasonable".[72] Within the region different regulators appear to place different levels of priority on promoting network efficiency, with some placing greater emphasis than others on "incentive regulation": for example the Norwegian regulator is subject to a revenue-cap, while the Danish TSOs have rate-of-return regulation and the Swedish TSO is "self-regulated in practice".[73]

Nordic TSOs in general (and again subject to some regional variation) appear to enjoy a higher degree of autonomy than in the UK or US systems. The transmission companies are subject to economic regulation, and the regulator approves access tariffs or tariff methodologies. However, the TSOs have significant decision-making responsibilities "devolved" to them. For example, the TSOs earn congestion rents whenever there is market splitting between countries, and the split of this revenue between TSOs is determined by the TSOs themselves through Nordel, and the allocation of this revenue towards funding expansion of cross-border capacity is voluntary.[74] At Nordic level the regulators do not appear to play a major role in decisions on expanding transmission capacity. This may reflect a belief that the Nordel system works well, and that the TSOs have a genuine commitment to building a Nordic market on sound economic principles.[75]

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[71] NordREG's memorandum of understanding (www.nordicenergyregulators.org).

[72] See, for example: *Annual Report 2006*, Danish Energy Regulatory Authority (DERA); *Guidelines for assessing reasonableness in pricing of national transmission network operations for 2005–7*, Finish Energy Market Authority, 2004; *Annual Report 2005*, Swedish Energy Markets Inspectorate; website of Norwegian Water Resources and Energy Directorate (NVE):
http://webb2.nve.no/modules/module_109/publisher_view_product.asp?iEntityId=9724.

[73] *Coordination of network operations and system responsibility in the Nordic electricity market*, Norden, 2006.

[74] "Nordel has agreed to use congestion incomes that arise from Nordic cross border trade as an earmarked source for investments in the Nordic transmission grid." (*Congestion management in the Nordic region*, p. 19, NordREG 2007).

[75] The lack of any vertical links between TSOs and generation or supply interests (apart from some cross-ownership in Finland) clearly makes it easier for the regulators to apply a "hands-off" approach.

Political Structures

Because Nordpool comprises multiple sovereign states (including Norway, which does not belong to the EU), political structures play a significant role. In particular, an institution that appears to have been important in the evolution of Nordpool is the Nordic Council of Ministers (Norden), an intergovernmental forum which brokered the necessary agreements behind the setting up and expansion of Nordpool,[76] and which produces detailed policy recommendations in relation to electricity transmission (see below).

3.1.3 Transmission networks

Figure 7 shows the Nordpool system. There are a number of constraints, both between countries and within Norway and Denmark. As a result, most of the time the market is split into two or more price areas. Nordpool operates with up to eight price areas, depending on the availability of transmission capacity between the areas. In 2005 there was a single price in only 32% of hours, and the market is often split into six areas.[77] The existence of transmission constraints has led observers to suggest that, from the perspective of a competition analysis, Nordpool is not a single market. For example, the European Commission in its sector inquiry suggested that at least four separate markets could be identified.[78] There are also suggestions that the generation markets are sufficiently concentrated that generators can influence the degree to which connections between price areas are constrained.[79]

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[76] See, for example, *Action Plan for Energy Co-operation 2006–9*, Norden 2005 (http://www.norden.org/pub/sk/showpub.asp?pubnr=2005:732).

[77] *Annual Report to the European Commission*, Energy Market Authority, Finland, 2006.

[78] Reported in the EFTA Surveillance Authority's sector inquiry report on Norway and Iceland.

[79] *Energy Sector Inquiry, Preliminary Report*, EFTA Surveillance Authority, 2006.

Figure 7: Nordpool transmission system[80]

Transit flows (defined as the difference between simultaneous import and export to/from a region) range from 4% of demand in Sweden to 13% of demand in Denmark, and are increasing.[81]

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[80] Nordel.

[81] *Steps for improved congestion management and cost allocation for transit*, Norden 2007.

Congestion management and response to congestion

Congestion management in Nordpool is a significant issue because congestion rents are quite large (Table 5),[82] and many of the constraints are persistent/structural.

Table 5: Congestion rents and counter-trading costs[83]

Year	Counter-trade	Congestion rents
2005	26.9	102.3
2004	9.7	48.5
2003	7.1	93.4
2002	11.6	98.3
2001	2.0	33.1

Notes
Figures from NordREG, €m per year.

Congestion is managed as follows: the Nordpool system is divided into eight areas which are separated by "structural" congestion, and in which prices may diverge. At the day-ahead stage, the TSOs determine likely available capacity between the price areas, based on an estimate of what dispatch and demand patterns will be on the following day. Available capacity can be reduced if, for example, there is congestion on the network within price areas. The TSOs publish the available capacities. Market participants then make their bids and offers for the following day for each price region. Nordpool sets the market clearing prices: prices in neighbouring areas will only be the same if the resulting contractual flow is less than the capacity on interconnections made available by the TSOs. On the day actual flows will be different than forecast, and the TSOs use counter-trading in the on-the-day market to manage and congestion which then emerges. Counter-trading is mostly needed as a result of outages and forecasting errors. Table 5 indicates the magnitude of congestion in Nordpool.

A comparison between the figures in Table 5 and Table 6 shows proposed investments of close to €1 billion against congestion rents in the €50–€100 million range annually. An independent study sponsored by Norden suggested that investment to reduce congestion within Nordpool would be moderately profitable, but that investment to expand capacity between Nordpool and continental Europe would be much more so (in particular because of the benefit of increased import capacity in dry years).[84]

3.1.4 Incentives on service quality and transmission losses

There is no uniform approach in this area: some countries have specific quality incentives (e.g., in Norway the regulator has introduced "quality adjusted income caps"), others do not. One

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[82] *Steps for improved congestion management and cost allocation for transit*, Norden 2007.

[83] *Congestion management in the Nordic region*, NordREG 2007.

[84] *Steps for improved congestion management and cost allocation*, Norden 2007.

Nordic TSO we spoke to explained that in that country here had been some discussion of this issue, but that because of the high security standards it would be hard to measure service quality accurately enough on a transmission (as opposed to a distribution) grid, i.e., it would be hard to distinguish meaningful changes in service quality from year-on-year "noise". The obligation to meet the security standard defined in the Nordic and national grid codes, monitored by the regulator, was considered sufficient to ensure appropriate levels of service quality.

Transmission losses can be quite significant in the Nordic region because of the long distances involved. We have been told that the effect on transmission losses is therefore included in and can be a significant part of the cost–benefit analysis for new investments in the region.

With regard to how the transmission system incentivises system users to minimise transmission losses there is variation between different countries. For example the Swedish and Norwegian systems both explicitly include transmission losses as a determinant of their transmission tariffs, while the Finnish system does not. However, we understand that there are no explicit (i.e., financial) incentives on the transmission companies themselves that are specifically focused on transmission losses, although the use of incentive regulation (via a revenue cap) in Norway may provide an incentive.

3.2 Transmission planning arrangements: key features

Although we provide some description of individual TSO practices, the main focus of this section is on the planning of transmission capacity between countries in Nordpool (and between the Nordpool area and surrounding countries).

3.2.1 Transmission planning process

Through Nordel, the Nordic TSOs have developed a Nordic Grid Code[85] which covers system planning and operation. The grid code is non-binding, and includes an explicit recognition that it must be "subordinate to the national rules in the various Nordic countries, such as the provisions of legislation, decrees and the conditions imposed by official bodies.'[86]

The Nordic Grid Code describes some of the technical standards for planning grid reinforcements and new interconnectors. Its general approach is as follows:

> *All parts of the power system shall be designed so that the electric power consumption will be met at the lowest cost. This means that the power system shall be planned, built and operated so that sufficient transmission capacity will be available for utilising the generation capacity and meeting the needs of the consumers in a way which is economically best. This also presupposes suitably balanced reliability. The long-term economic design of the grid means to balance between investments and the*

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[85] *The Nordic Grid Code*, Nordel 2007.

[86] *Nordic Grid Code*, p. 6.

cost of maintenance, operation and supply interruptions, taking into account the environmental demands and other limitations.[87]

In terms of process, Nordel has a permanent committee, the Nordic Planning Committee (made up of the heads of system planning of each of the member TSOs), responsible for producing and updating a "top-down" analysis of the overall needs of the Nordic region, the Nordic Grid Master Plan (see below).[88] According to the most recent Nordel Annual Report, the next version of this report should be produced during 2007.

Nordel then makes recommendations for specific investments on the basis of the Master Plan. These recommendations are non-binding, and the process itself is relatively informal, because all co-operation between the Nordic TSOs is on a voluntary basis. Nordel undertakes cost–benefit analyses to assess potential investments, but these are not published.

National TSOs then make their own transmission plans (generally on an annual basis). All TSOs have in-house planning divisions. The plans reflect a mix of national and Nordic criteria: compliance with the Nordic Grid Code and national requirements, meeting national needs (on reliability and economic criteria), and responsiveness to the Nordel recommendations. National TSOs also undertake cost–benefit analyses to assess investments (in some cases this is a regulatory requirement), but these are generally not published. The Norwegian regulator describes their process as follows:[89]

> *In the national grid the TSO (Statnett) has the responsibility for the planning process and issuing of the national grid study. The yearly updated grid studies are submitted to the regulator (NVE) for consent. The study period for the grid development is minimum 10 year. The measures to improve upon the grid is only a part of the study among other topics as energy and plant statistics, security of supply, spare parts situation, environmental, economical and technical presumptions, specific circumstances for the area, description of the existing grid, operating conditions, tariffs and future grid development.*
>
> *The studies must describe bottle necks, and how operational situations may create and influence congestion situations in the grid. Measures to reduce or eliminate congestions in the grid are one goal of the study.*

The Nordel process is also now evolving to allow for "multi-regional planning", to include links with the Baltics and Central Europe. Recent proposals for a common EU approach to planning (described elsewhere in this report) are also likely to have an effect.

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[87] *Nordic Grid Code*, p. 16.

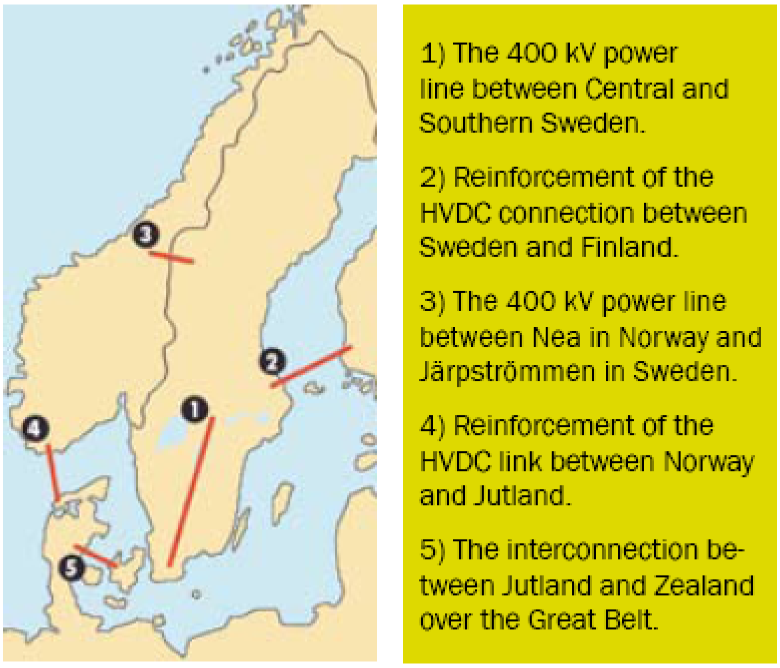
[88] In principle this appears to be intended as a public document, although we were not able to find it via the internet.

[89] *Report on regulation and the electricity market, Norway*. Norwegian Water Resources and Energy Directorate (NVE), July 2006.

Priority investments

In 2003 Nordel published the first "Nordic Grid Master Plan", in which 11 possible transmission upgrades were considered. Five of these were subsequently selected as priority investments (see below for the selection criteria), as shown in Figure 8. The total cost of these investments is around €1 billion.[90]

Figure 8: Priority reinforcement measures[91]



3.2.2 Implementation and cost recovery

Investments between TSO systems proceed on the basis of bilateral agreements between TSOs. Up to now the costs of cross-border interconnectors have been covered by the two TSOs involved, except that congestion rents are usually applied to the investments (with the rents usually split equally between the two TSOs involved).[92] There is no general mechanism for sharing revenues between TSOs: each TSO collects revenues from its own connected customers and from its share of the congestion rents, and is responsible for costs within its own region.

There is also no formal obligation on TSOs to invest in line with Nordel recommendations. The mechanism is an entirely voluntary one. Nonetheless, we understand that all of the "priority

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[90] See *The future infrastructure of the Nordic electricity system*, Nordel 2003.

[91] Graphic from *The Swedish Electricity Market and the Role of Svenska Kraftnät*, Svenska Kraftnät, 2007.

[92] In general congestion rents are collected by Nordpool, and then shared out among the TSOs on the basis of a set of principles arrived at by common agreement.

reinforcement measures" discussed above are underway (see Table 6 below), although there is some doubt over the Denmark–Norway link (Skagerrak IV).[93] There is an ongoing debate as to the effectiveness of this voluntary approach, which we describe in Section 3.5 below.

Table 6: Nordel plan for capacity expansion[94]

Project	Commissioning date	Cost estimate (€m)
Fenno-Skan 2	2010	260
Nea-Järpströmmen	2009	66
South Link	2012/13	150-230
Skagerrak IV	2012	260
Great Belt	2010	160
Total		**896-976**

Notes
Data from Nordel

3.2.3 Responding to market needs

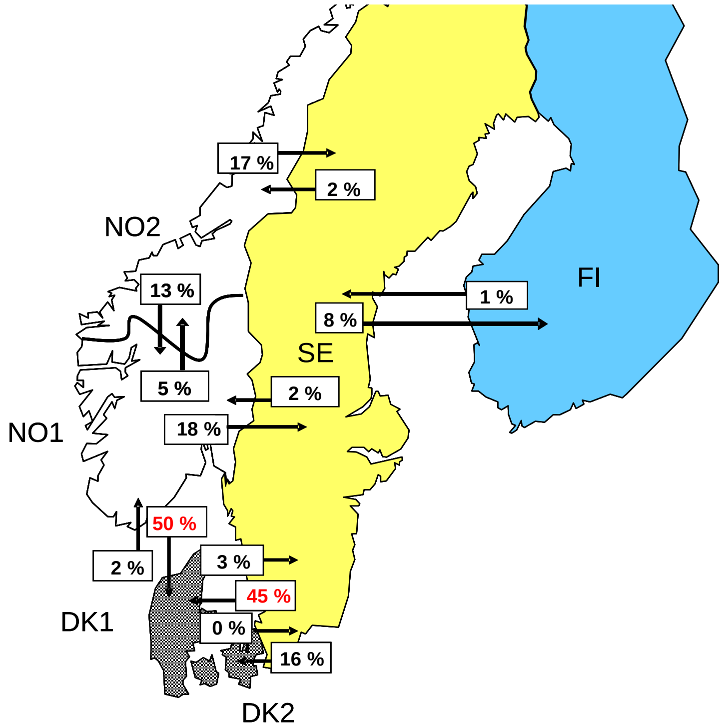
The key point here is the role of the Nordpool market splitting arrangements: the existence of distinct price areas makes market needs for increased interconnections explicit and quantifiable. Figure 9 shows the extent of congestion (by proportion of time congested) in 2005. A comparison of the data in Figure 9 with the set of "priority measures" discussed earlier shows a broad correspondence between congestion and the chosen investments.[95]

[93] The most recent *Nordel Annual Report* (2006) says that "[t]he bilateral studies have finished, and business cases are under preparation for the Boards of each company. The investment decision is scheduled for 2008/09."

[94] Data from *Prioritised cross-sections: Reinforcement measures within the Nordic countries, Status June 2007*, Nordel. Project numbers correspond to numbering in Figure 8.

[95] Bearing in mind that the amount of time spent congested is only a rough indicator of the economic value of additional capacity (for example, it dos not take into account the size of the difference in marginal production costs between two areas).

Figure 9: Congested links (proportion of time, 2005)[96]



Some economists have, however, criticised the Nordpool system because the price areas have been pre-selected on a "political" basis and do not allow for other price differences that might arise under a more comprehensive system.[97] For example, a constraint within Sweden or within Finland would not be revealed by the Nordpool system, because each of those countries is a single price area. The criticism is clearly correct as a matter of economic theory, but we are not familiar with any quantitative work to analyse its materiality in practice.

At national level, TSOs apply a mix of "top-down" (forecasts of future market needs based on forecast growth in demand and developments in patterns of generation, deployment of renewables etc, sometimes involving scenario analysis) and "bottom-up" approaches (forecasts on the basis of information provided by the TSOs' customers, i.e., the generators, distribution companies and large users who are directly connected to the transmission system).

3.2.4 Trading off transmission and non-transmission investments

The Nordic TSOs have agreed to harmonize their tariffs for generation use of system charges over time. However, at present there is no single Nordic approach to this issue. One TSO (Svenska Kräftnet in Sweden) makes use of locational pricing, with higher charges for generation

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[96] *Development of Interconnection in the Nordic Countries*, Timo Toivonen, President & CEO, Fingrid Oyj, January 2006.

[97] See for example *Steps for improved congestion management and cost allocation for transit*, Mikael Togeby, Ea Energy Analyses, Hans Henrik Lindboe, Ea Energy Analyses, Thomas Engberg Pedersen, COWI, study for Norden, 2007.

located in the north of Sweden (and load in the south of Sweden), reflecting the increased system costs associated with north-to-south flows.

The other Nordic TSOs generally have no locational element in their charging, except for differences related to transmission losses. It appears therefore that in the Nordic region there are limited mechanisms in place to address the trade-off between investment and alternative solutions.

There are different views within the region as to the potential for efficiency gains from introducing mechanisms (whether incentive-based or planning-based) to co-ordinate transmission investments with locational and related decisions for generation and load. One TSO planner told us that in his country there is little potential to find alternatives to new transmission investments, because new generation and load in the region typically has little choice over location. Arguably this would apply, for a variety of reasons to hydro, nuclear and large resource intensive energy users such as paper and pulp manufacturers.

By contrast, there is a perception in Norway of a clear trade-off between investment in generation and investment in transmission. Due to demand growth in central Norway, the Statnett 2005–2020 plan identified the need for significant grid reinforcement in this region. Statnett also noted that the reinforcement could be avoided or delayed if new generation were to connect in this region—but also that the grid tariffs gave no incentive to generators to do so. Similarly, new generation (wind and hydro) in the north of the country is attractive from the generator perspective because new projects would not face the high cost of reinforcing the transmission network to connect them. Statnett therefore developed a new, reduced, tariff for new generators connecting in locations which result in savings on grid reinforcement (thus introducing a locational element unrelated to transmission losses).[98]

3.3 "Reliability" and "economic" investments

The investments planned through the Nordel system, are all in new interconnections between the national networks. They are all essentially "economic" rather than "reliability" investments, i.e., they are justified on the basis of increased economic efficiency (including enhanced competition) rather than being necessary to ensure compliance with reliability standards.[99] The key question here therefore is what criteria are applied to assess economic efficiency (questions of co-ordination to achieve implementation are discussed in subsequent sections).

The criteria are essentially those described in section 3.3.2 below. The essential points are that:

- the criteria are "economic" in nature, but are broader than just the impact on total production costs;

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[98] *Grid Development Plan 2005–2020*, Statnett 2005.

[99] Flows between countries cannot give rise to reliability issues, because if there is significant congestion within any of the national networks as a result of cross-border flows, the capacity on that link can be down-rated (through the market splitting mechanism)—i.e., congestion is "pushed to the borders".

- they include factors such as impact on competition that are potentially significant, but hard to assess qualitatively (and we understand that they are not so assessed); and
- the assessment explicitly accounts for uncertainty via a scenario-based approach.

3.3.1 "Reliability" investments

The Nordic Grid Code gives technical engineering criteria for grid planning. As explained above, these standards apply to investment within each national grid, but cannot trigger investment between countries without considering the economic criteria discussed below. In common with the rules in other jurisdictions, the standards are expressed in terms of the extent to which the system must be robust to faults of varying degrees of severity. Some of these conditions are summarised in Table 7. Not all of the technical criteria are common to each country within Nordpool: for example, over-loading of transformers is permitted up to 120% of nominal rating for one hour in Sweden, but up to 150% of nominal "briefly" in Finland.[100]

Table 7: Post-fault performance in Nordpool[101]

<table>
<tr><td colspan="3" rowspan="4">Acceptable consequences
A Stable operation, local consequences and limited intervention of system protection
B Controlled operation, regional consequences
C Instability and breakdown
A/B Consequences in accordance with B for faults in previously weakened area, otherwise A.
B/C Aim should be to limit the consequences according to B but for all faults this cannot be fulfilled
¹ The operating situation has been adapted during 15 minutes after the fault by using the means available (disturbance reserves, etc.).</td><td colspan="7">Pre-Fault Conditions</td></tr>
<tr><td colspan="4">Normal operation</td><td>Alert-state operation</td><td>Disturbed operation</td><td>Emergency operation</td></tr>
<tr><td>Grid intact</td><td>Planned maintenance</td><td colspan="2">Spontaneous loss and adapted operation¹</td><td rowspan="2">Exceeded transfer limits / insufficient reserves. Adapt operation by adjusting new transfer limits and / or activating reserves within max. 15 min.</td><td rowspan="2">Exceeded transfer limits and / or insufficient reserves</td><td rowspan="2">Exceeded transfer limits and / or insufficient reserves
Load shedding effected</td></tr>
<tr><td>No critical components out of operation
PC0</td><td>Shunt or series component out of operation
PC1</td><td>Shunt component out of operation
PC2</td><td>Series component out of operation
PC3</td></tr>
<tr><td rowspan="5">Fault groups</td><td rowspan="3">N-1 faults</td><td>Single fault that does not affect series components FG1</td><td rowspan="3">A</td><td rowspan="3">A</td><td rowspan="3">A</td><td>A</td><td rowspan="3">B/C</td><td rowspan="2">B/C</td><td>B/C</td></tr>
<tr><td>Single fault that affects series components FG2</td><td>A/B</td><td rowspan="4">C</td></tr>
<tr><td>Uncommon single faults and special combinations of two faults FG3</td><td>B</td><td rowspan="3">C</td></tr>
<tr><td rowspan="2">Serious faults</td><td>Other combinations of two faults caused by the same event FG4</td><td>B</td><td>B</td><td>B</td><td rowspan="2">C</td><td rowspan="2">C</td></tr>
<tr><td>Other multiple faults FG5</td><td>C</td><td>C</td><td>C</td></tr>
</table>

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[100] *Nordic Grid Code*, Nordel 2007.

[101] *Nordic Grid Code*, Nordel 2007.

There are also national grid codes that apply to lower voltages. For example, in Finland the 400kV system is designed and operated to the Nordic Grid Code, but the 110kV system is subject to the national grid code.

An “n–1” standard applies in much of Nordpool, as shown in Table 7. However, there is some evolution, at least in some parts of the region away from a strict “n–1” toward a less uniform approach that appears implicitly to involve more economics (i.e., incorporates cost–benefit considerations, albeit on a qualitative basis). Thus Statnett writes that:[102]

> *Traditionally, grid planning and load limitation has been based on the “N–1 criterion”, which means that a system must be able to tolerate the breakdown of one component without causing an outage in the electricity supply. The N–1 criterion was previously a decision making criterion, but is now used more as an aid in planning. Nordel’s dimensioning rules (see the Nordic Grid Code) provide a modified N–1 criterion and specified acceptable consequences of various combinations of operational conditions and fault incidents. Statnett bases its dimensioning and determination of load limits across national borders and in contexts where faults can have consequences for our neighbours, on Nordel’s recommendations.*
>
> *Statnett’s objectives with regard to quality of supply and a defined “window of opportunity”*[103] *set limits for how large outages are acceptable. The main principles apply in operations and are a fundamental prerequisite for maintenance and grid planning. The grid must be strengthened if it is economically rational to do so, or if it has to be done to satisfy the limits in the given “window of opportunity”.*

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[102] *Grid Development Plan 2005–2020*, Statnett, June 2005.

[103] The phrase “window of opportunity” here refers to a set of reliability standards, defined by specifying maximum acceptable consequences of an outage. These are defined further in the same text, and include for example “[a] connection point in the main grid shall have maximum 2 outages per year”.

3.3.2 "Economic" investments

The Nordic TSOs have developed an agreed methodology for assessing the costs and benefits of new interconnections within Nordpool. The methodology was developed through Nordel and used to identify the "priority cross-sections" which form the current transmission expansion plan. The methodology takes account of six categories of benefit.[104]

1. "Production optimisation and energy conversion": measures the changes in consumer and producer surplus and congestion rents. Nordel comments that "this is the most important socio-economic aspect of an expansion. By calculating the socio-economic value at Nordic level the joint benefit becomes more evident. Investments in infrastructure shift much larger amounts between the consumers and the producers than the actual investment. In a joint Nordic assessment the reallocation typically goes from producers to consumers."
2. "Reduced risk of power failure": Nordel views this factor as relatively insignificant (though note that this is distinguished from the risk of rationing).
3. "Changes in losses".
4. "Lower risk of energy rationing": can be a significant factor in Norway, because of the need for imports in dry years.
5. "Trade in regulating power and ancillary services": interconnection can allow such services to be traded across borders.
6. "The values of a better-functioning market": an assessment of the impact of expansion on the ability of generators to exercise market power. Nordel comments that expansion will normally increase competition but might reduce it: market power could be "imported" into a previously competitive region.

It is interesting to note the range of factors that feature in this list, which is much broader than the typical "traditional" cost-minimisation approach. In this respect a useful point of comparison is with the TEAM methodology recently adopted by the CAISO, discussed elsewhere in this report.

Unfortunately Nordel does not publish its cost–benefit analyses, nor describe in detail its methodology, and it is therefore difficult to see how these criteria are analysed in practice. However, we understand that some of the criteria (notably the last) are assessed on a qualitative basis. Statnett provides some insight into its own internal practice.[105]

> *Our overarching objective is to ensure the societally rational development of the power system. All planning in relation to the grid is done, therefore, on the basis of economic criteria. While benefits and costs are quantified as far as possible, importance is also attached to other factors that are not quantifiable.*

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[104] Quoted from *The future infrastructure of the Nordic electricity system*, Nordel 2003.

[105] *Grid Development Plan 2005–2020*, Statnett 2005.

The quantifiable cost–benefit effects of a measure are the value of increased capacity in the grid and of reduced transmission loss-, outage-, tariff- and system operation costs. These benefits must overall exceed the investment and operational costs associated with the measure. Measures aimed at increasing utilisation of the existing grid are always considered as alternatives to building new power transmission facilities.

Other factors that are also important are chiefly environmental impact and security of electricity supply. We are concerned to find solutions that are environmentally sound, and we emphasise the environment on a par with technical and economic considerations.

An important issue is whether costs and benefits are measured on a national or Nordic basis. At present the approach is a compromise between the two (see later discussion). Statnett for example states that:[106]

Investments in the Norwegian main grid are assessed in relation to the Nordic power system as a whole. While our decision-making criterion is normally whether the investment will be socio-economically profitable for Norway, in analysing potential investment we also take into account the economic consequences for the other Nordic countries.

The Nordic Grid Code also discusses cost–benefit assessment for investments in new capacity. It require the following to be taken into account: investment costs; operating and maintenance costs; environmental costs (environmental consequences are often only evaluated qualitatively); congestion costs; losses; outage costs; and system costs (undefined).

The Nordic planning methodology uses a scenario analysis approach to deal with uncertainty. For the 2007 update, Nordel has developed three scenarios that:[107]

describe different future situations in view of economic growth, climate policies, energy prices, etc. The first scenario, which is the base scenario, prolongs current trends and reflects likely outcomes of existing plans, policies, support schemes for renewables etc. The global focus on climate is continued at a moderate level. In the second scenario, called Climate & integration, the growth in world economy will exceed current expectations, and the resulting growth in the demand for oil, gas and coal will reduce capacity margins on the supply side (production and transportation) and lift prices and volatility. In the third scenario, called National focus, global economic growth will decline as compared to the base scenario even though the prices of oil and gas are higher in this scenario. The focus on the mitigation of CO_2 emissions is relatively high also in this scenario, but international co-operation is poorer.

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[106] *Grid Development Plan 2005–2020*, Statnett 2005.

[107] *Annual Report 2006*, Nordel.

3.4 Co-ordination of transmission planning

As discussed above, it is a notable feature of the Nordic system that the inter-TSO co-ordination occurs on an entirely voluntary basis, and with limited ability for TSOs to be financially compensated for investments that provide benefits outside their own area. A number of factors make this system more likely to succeed in the Nordic region than elsewhere:

- There is a strong political will to create and sustain an integrated Nordic market;
- There is a strong history of Nordic co-operation in many areas, formalised in 1952 with the creation of the Nordic Council and subsequently strengthened through the 1962 Helsinki Treaty and 1971 creation of the Nordic Council of Ministers. Arguably a Nordic "consensus culture" has developed that facilitates effective co-operation;
- Because of the diversity of generation, and in particular the prevalence of hydro in some countries and thermal generation in others, increased interconnection creates large gains from trade and is likely to be "distributionally benign", i.e., to create a win-win outcome where the benefits to the hydro-based countries (Norway and Sweden) in dry years outweigh the costs in wet years, and vice-versa for the thermal-based countries (Denmark and Finland).

However, there is also a heated debate within the Nordic region as to how effective the voluntary system is. Some TSOs argue that it is an effective system that enjoys the benefits of a low level of bureaucracy, and lack of political interference that might lead to less efficient investment decisions by introducing political pressure to choose projects on grounds other than socio-economic benefit.

However, other parties, including the Norwegian TSO Statnett, are rather critical of the system. In its most recent published transmission plan Statnett says that "[w]e have been and remain concerned to see a more binding collaboration taking shape, as the current form of collaboration within Nordel is not sufficiently robust. It is also extremely time-consuming."[108] Most recently, a statement issued by many of the largest utilities active in the region claimed that "[i]nvestment planning is presently made primarily from national perspectives despite the fact that investments in one country often have significant implications for the neighboring countries".[109]

The other Nordic TSOs generally reject these criticisms. In response to the statement cited above, the CEO of Fingrid released a statement saying that "[t]he co-operation model applied by the Nordic TSOs comprises strengths such as integrated decision-making and implementation of grid investments. The Nordic TSOs have already agreed on an investment programme of one thousand million euros, which will reduce market segregation distinctly."

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[108] *Grid Development Plan 2005–2020*, Statnett 2005.

[109] Joint statement by Vattenfall, Norsk Hydro, DONG, Fortum and others, reported in Platts European Power Daily, 20th September 2007.

It is beyond the scope of this report to assess these criticisms. However, a 2006 report commissioned by Norden lays out some of the perceived problems with the current system, providing a concrete (albeit non-quantified) example of the potential for a predominantly national perspective to distort transmission planning:[110]

> *A case in point could be the possible large scale development of wind power generation in Northern Norway. It would require Statnett building large main grid extensions to transport the power southwards since Northern Norway is a surplus area in summer time. However, it could very well be a cheaper solution to increase the transmission capacity through Sweden. The "Swedish Solution" could have several advantages including more favorable terrain for building grid infrastructure (e.g. woodland in Northern Sweden vs. rugged mountainous terrain in Northern Norway). With the present organization with national TSOs, this solution has, however, several challenges, amongst them financing. Such an expansion would have large external effects into the Swedish grid and it would be hard to estimate and agree on the value of these.*

3.5 Evolution

In light of the criticisms described above, and in particular the objections voiced by Statnett, there has been much discussion of possible alternatives to the current Nordic model of voluntary co-operation. In its 2004 Akureyri declaration the Nordic Council of Ministers asked the Nordic TSOs to investigate the possibilities for enhanced integration, including in the planning and financing of network investments. Nordel subsequently produced a report that laid out a range of alternatives.[111]

1. Status quo (bilateral financing).
2. Bilateral financing plus use of congestion rents.[112]
3. The creation of a "Nordel grid planning and financing mechanism (Nordel P&F)" that would replace the present Nordic Planning Committee and would have some measure of legal authority in regard to transmission planning. Financing would continue to be provided by the national TSOs.
4. The creation of a "Nordic grid investment company" that would build and own all new "common" investments, and would be financed by congestion rents and a common Nordic tariff or trading fee.

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110 *Coordination of network operations and system responsibility in the Nordic electricity market*, Norden, 2006.

111 *Enhancing Efficient Functioning of the Nordic Electricity Market: Summary and Conclusions*, Nordel, available at: http://www.ergeg.org/portal/page/portal/ERGEG_HOME/ERGEG_PC/ARCHIVE1/CREATION_OF_REM/NORDEL%20APPENDIX.PDF.

112 This option has since been adopted, as described earlier in this report.

Nordel concluded, however, that only the second of these options (i.e., a relatively minor change from the status quo) was feasible in the short term. It committed to implementing the second option, and to considering (in 2007) the potential for creating a permanent planning secretariat within Nordel to replace the current committee system.

Of the TSOs only Statnett would support a move to options 3 or 4. It has stated that "Nordel's proposals should have been more ambitious in relation to facilitating an even more binding Nordic collaboration. …as the current form of collaboration within Nordel is not sufficiently effective."[113] Statnett's preferred solutions are either a "Nordic investment company", or alternatively an enhanced planning function ('a Nordic planning secretariat'). Statnett believes that the existing model of bilateral negotiations on each interconnector will be insufficiently effective in a future that will require rapid change.[114]

In response to Nordel's work, Norden commissioned the 2006 report cited above. The report concluded that "increased commitment and focus on the Nordic perspectives is needed from the TSOs", and argued that there would be large potential efficiency benefits from a switch to a joint Nordic TSO (the most radical solution, involving a merger of the four existing TSOs). It expressed some scepticism about the "Nordic grid investment company" option outlined by Nordel, which it believed "could speed up investments and improve the Nordic co-operation…[but] would most likely require some negotiations between the TSOs and the fundamental conflict would not be resolved".

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[113] *Grid Development Plan 2005–2020*, Statnett 2005.

[114] *Ibid.*

4 Great Britain

4.1 Background

4.1.1 Industry structure

The electricity supply industry in GB is privatised with the exception of the nuclear generators, and both the wholesale and the retail markets are fully liberalised. The activities of generation, transmission, distribution, and supply (the reselling to end consumers of electricity purchased on the wholesale market) are separate and cannot be carried out by the same legal entity. Excluding the two nuclear generators, British Energy and British Nuclear Fuels, the six major energy companies have both generation and retail supply businesses: Electricité de France, Scottish Power (recently acquired by Iberdrola), Scottish and Southern Energy, RWE, E.ON, and Centrica (the former gas monopoly). All of the retailers supply both gas and electricity, and most of the companies also own electricity distribution businesses.

The wholesale electricity market across GB is a bi-lateral contracting market: generators and suppliers contract with each other, generators self-dispatch, and all parties notify the SO[115] of their intended physical positions. The SO manages real-time imbalances between supply and demand by accepting bids/offers in a balancing market (the "Balancing Mechanism" or BM). The great majority of electricity (>95%) is traded outside the BM, either bilaterally over-the-counter or through exchanges. These arrangements were introduced in 2001, replacing the former compulsory "Pool" market under which generators were obliged to bid into a gross pool and were centrally dispatched by the SO.

There are three electricity transmission companies in GB: Scottish Hydro-electric Transmission Limited (SHETL) owns the high voltage network in the north of Scotland; Scottish Power Transmission Limited (SPTL) owns the network in the south of Scotland; and National Grid Electricity Transmission (NGET) owns the transmission network in England and Wales. SHETL is owned by Scottish and Southern Energy and SPTL is owned by Scottish Power, but the NGET group of companies does not own other interests in the GB electricity market, and is prevented by licence obligations (see below) from acquiring any. Following implementation of the BETTA (British Electricity Trading and Transmission Arrangements) reforms in 2005, NGET is also the SO for the transmission network across the whole of GB (the GBSO). All three companies are normal private (for profit) companies.

4.1.2 Regulation

The system for regulating the electricity industry in GB has been in place since privatisation in 1989. It consists of a mixture of ex-ante economic regulation (primarily of the networks) and ex-post general competition law (applied primarily to generation and supply). Charges for use of

[115] The System Operator is responsible for operational decisions on matters such as network configuration and switching, and is also responsible for ensuring the real-time balance of supply and demand and for managing network constraints. The System Operator role is distinct from that of Transmission Owner.

the networks are reviewed and controlled by the regulator, and there is a cap on the total revenues which the network businesses can earn.

The powers and duties of the regulator, Ofgem, are set out in legislation.[116] Its duties are to protect the interests of consumers of gas and electricity, wherever appropriate by promoting effective competition. Its powers include the ability to fine the companies up to 10% of annual turnover for a breach of competition law or for a breach of the regulatory rules. Ofgem's board is appointed by the government but it is not otherwise under the control of the executive: Ofgem is funded by a levy on the industry which is (formally) approved annually by the UK legislature. Its decisions are subject to appeal to the UK Competition Commission, which is also the phase two competition authority in the UK, responsible for detailed investigations of mergers, market reviews, and breaches of competition law.

All companies in the industry are required by law to hold a "licence" to operate, issued by Ofgem.[117] The licences are made up of "conditions" which set out the detail of the companies' responsibilities (for example, the requirement to set tariffs in line with a methodology that has been approved by Ofgem), and, in the case of the network businesses, state how much revenue the companies may earn by charging for the use of the network. The licence conditions evolve over time because Ofgem has the power to alter them (subject to appeal).

In addition to the obligations in the licences, the network companies also have duties, for example, the duty not to discriminate between different users or groups of user, set out in primary legislation.[118]

Industry rules

The detail of the commercial relationships between the industry participants, as well as detailed technical requirements relating to the operation of the system, are contained in documents known as "industry codes':[119]

- the Balancing and Settlement Code (rules on charging for imbalances between notified and physical generation/demands);
- the Connection and Use of System Code (commercial matters relating to connection and use of the transmission system);
- the Distribution Code (technical matters relating to use of the distribution networks);

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[116] The main pieces of relevant legislation are: the *Electricity Act 1989*, the *Competition Act 1998*, the *Utilities Act 2000*, the *Enterprise Act 2002*, the *Sustainable Energy Act 2003*, and the *Energy Act 2004*.

[117] The texts of the licences are available from Ofgem's "Electronic Public Register" at http://epr.ofgem.gov.uk. For example, NGET's electricity transmission licence is at http://epr.ofgem.gov.uk/document_fetch.php?documentid=8792.

[118] The *Electricity Act 1989*, the *Utilities Act 2000*.

[119] Also available at http://epr.ofgem.gov.uk.

- the Grid Code (technical requirements for use of the transmission system);
- the Master Registration Agreement (procedures governing the process for distribution network operators and suppliers to handle requests from customers to switch supplier);
- the System Operator–Transmission Owner Code (defines the relationship between the GBSO and the three TOs); and
- the Distribution Connection and Use of System Agreement (commercial terms for connection to and use of the distribution networks).

The main difference between the licence conditions and the industry codes is that whereas only Ofgem can modify the licence, industry participants can suggest changes to the codes, which Ofgem decides whether to accept or reject (subject to appeal to the Competition Commission). Thus, for example, both generators and demand customers have the right to suggest a modification to the Grid Code, and NGET has the obligation to suggest modifications which it considers would make the code more effective. Ofgem is able to enforce compliance with the industry codes because adherence to the codes is a licence requirement, and Ofgem can impose fines for breach of licences.

Price controls

The network businesses operate subject to price controls: the prices they can charge users of the networks, and/or the total revenues they are allowed to earn, are set by Ofgem. Price controls are implemented through modifying the relevant licence conditions, typically every five years. Ofgem has broad discretion over the form of the price control, but typical practice is as follows:

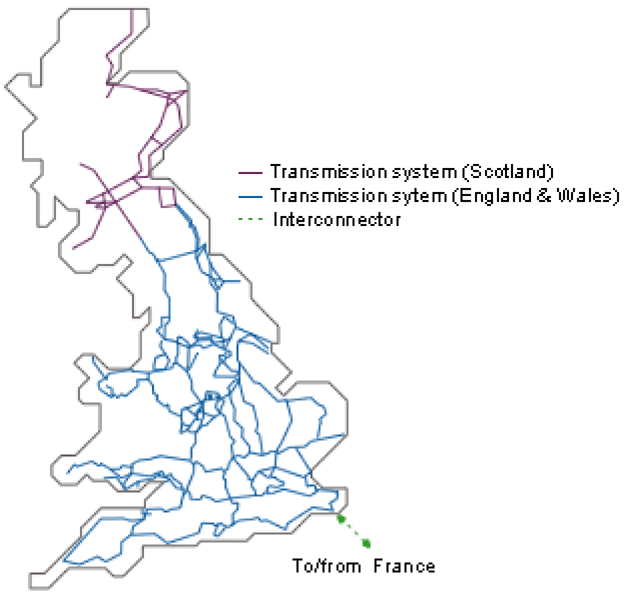
- the network companies submit to Ofgem a forecast of expenditure they would like to make over the subsequent price control period;
- in the case of the transmission system, the forecast might be broken down into expenditure on maintaining and replacing the existing system and expenditure on delivering new network capacity sufficient to meet the expected demands of new generators and growth in electricity demand;
- Ofgem reviews the forecasts;
- as part of the review process Ofgem employs technical engineering consultants to examine detailed business plans of the network companies, and also consults with network users;
- Ofgem also approves a certain amount of capital expenditure; and
- Ofgem builds up a forecast of required revenues for the subsequent period, to include operating costs and both depreciation and a return on capital invested.

Once the required revenues for the price control period have been set by Ofgem and accepted by the companies (or imposed following appeal to the Competition Commission), the companies' revenues/prices are fixed.[120] During the price control period the companies have a strong incentive to be efficient, because if they are able to deliver their obligations at a lower cost than that agreed in the price control, they can keep the difference until the next price control period. Conversely, if there is an over spend, the companies must fund this. The companies are also able to keep the benefits of deferring or avoiding agreed capital expenditure, subject to a review by Ofgem to ensure that network performance will not be prejudiced by lack of investment.

4.1.3 Transmission networks

The transmission network in GB (shown in Figure 10 below) is not synchronised with those in neighbouring regions, but is linked through DC interconnectors with both France and Northern Ireland.

Figure 10: GB transmission network



Within GB there are some significant constraints, particularly between Scotland and England and within Scotland. Furthermore, as a result of subsidies for renewable generation, there are many proposals for new generation projects, particularly in Scotland, which have resulted in the need for reinforcement of the transmission system and a large "queue" of projects waiting for connection agreements.

A distinction is made between the functions of SO and transmission system owner (TO). The role of the SO is to manage the day-to-day operation of the systems owned by the TOs. The SO directs the TOs how to configure the system, and is responsible for ensuring that network constraints are managed and imbalances in the supply–demand balance are resolved. The TOs are

[120] Either prices (e.g., per unit of electricity transmitted) or revenues may be fixed, depending on the allocation of volume risk.

responsible for building and maintaining their networks, but do not have direct contact with network users. The SO sets charges for use of the TOs' systems, and also manages the process by which new customers get connected to the system. The TOs and the SO co-operate on network planning (see below). Both TO and SO functions are subject to price-cap type incentive regulation: although the incentive mechanism applied to the SO functions of energy and system balancing is relatively weaker than that applied to the other functions because it is reset every 12 months rather than every five years. All of the capital expenditure on the network is funded through the TO price controls.

4.1.4 Congestion management

The GB Security and Quality of Supply Standard ("SQSS") requires the companies to plan their systems to meet technical engineering standards of reliability (described in section 4.3.1 below).[121] However, these standards are not designed to ensure that there is no congestion: congestion arises because the out-turn of demand and generation patterns will be different from that forecast for planning purposes, or actual peak demand could be higher than the planning standard because of cold weather; additionally, the SQSS allows transmission investment to be deferred if the engineering standards can be met through rescheduling of generation (constraining some generators on and others off) more cheaply than through investment.

The SO is able to manage congestion by reconfiguring the transmission system and by paying generators (or large loads) to alter their patterns of generation/consumption. The latter can be achieved either by accepting bids/offers in the BM or by pre-contracting with users. Typically this involves constraining off some generation and constraining on an equivalent volume of generation the other side of the transmission constraint, but sometimes the SO is able to contract with demand sites to resolve transmission constraints more cheaply. The SO is obliged to select the best (cheapest) way of resolving constraints, and Ofgem has encouraged NGET to find ways of encouraging large consumers to participate in tenders to offer services which can be used to resolve constraints.

The cost of resolving transmission constraints is subject to an incentive scheme. The total "external" costs[122] of system operation are forecast in advance, and a revenue allowance is set. Sharing factors and a cap/collar determine the extent to which the SO is able to keep out-performance or has to fund under-performance. The current scheme (2007/8) provides that costs are passed through if they fall in a "deadband" of £430–435m. Outside this range the SO bears 20% of the financial risk, subject to a cap/collar of £10m each way.[123]

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[121] *GB Security and Quality of Supply Standard, version 1.0* September 22, 2004, paragraph 4.10 (available from the NGET website).

[122] "External" costs are services for which the SO contracts externally, as distinct from its "internal" costs such as staff and buildings.

[123] *National Grid Electricity Transmission System Operator Incentives from 1 April 2007*, Ofgem 2007.

The incentive scheme has always been set for a 12-month period, though Ofgem has frequently suggested that a longer period might be implemented.[124] The benefits of a longer scheme would be an increased ability to trade off between capital expenditure and operational costs (though see below for NGET views—it is not clear that a mechanism exists for the SO to require network investment). The disadvantages of a longer scheme would be that a large element of the costs may change in unpredictable ways (for example, may be driven by wholesale electricity prices). The current form of the scheme incentivises the total external costs—i.e., the cost of managing transmission constraints plus the cost of maintaining the overall supply–demand balance, perhaps because the same SO action can have an impact on both system and energy balance. For example, if there is a transmission constraint and the system as a whole is also short, constraining on a generator on the "right" side of the constraint could help to solve both problems (in gas there are separate schemes for the different categories of external SO cost).

The cost of managing transmission constraints has risen (mostly because of increased wholesale prices) and is forecast to rise further as a result of the large volume of additional wind generation likely to connect at the extremities of the network. Table 8 shows constraint costs in absolute terms and as a proportion of total external SO costs.

Table 8: Constraint costs[125]

	2004/5	2005/6	2006/7
Constraint costs (£m)	15	80	108
Total external SO costs (£m)	302	537	551
Constraint costs (% of total external SO costs)	5%	15%	20%

Notes
Figures published by Ofgem
2004/5 figures refer to England and Wales only

The significant increase in constraint costs between 2004/5 and 2005/6 is due to the expansion of the scope of the scheme to include Scotland.

The scheme is designed to encourage the SO to be efficient in procuring the services it needs to balance the system (for example, in choosing whether to contract in advance for reserve generation or to purchase energy in the balancing mechanism). It is not designed to have an impact on the way that investment in the transmission system is planned.

The SO has expressed some reservations about the way in which the incentive scheme operates:

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[124] See, for example, *Review of Gas and Electricity System Operator Role, Functions and Incentives: Initial Thoughts*, Ofgem August 2007, paragraphs 2.44 to 2.47.

[125] Taken from *Review of Gas and Electricity System Operator Role, Functions and Incentives: Initial Thoughts*, Ofgem August 2007.

- that the SO incentive scheme allows the SO to pay the Scottish TOs to accelerate or re-organise their network outages where this is an efficient way of managing total SO costs, but that the scheme is not generous enough to allow for equivalent (internal) payments to re-arrange network outages in England and Wales; and that
- the rearrangement of transmission outages in Scotland mentioned above is limited to changes to the annual outage plan, and the SO states that "there is currently no broader financial compensation or incentive framework on the Scottish TOs [or, by extension, the England and Wales TO] to fund actions or investment to minimise constraint costs throughout the system investment and planning timeline".[126]

The SO comments above suggest that the incentive scheme can operate, albeit imperfectly, to optimise within year planning of transmission system outages, but that it cannot incentivise longer-term actions. Investment to optimise constraint costs should be taken into account in the transmission planning process because it is part of the compulsory engineering standards that must be applied—but there is no direct financial incentive on the companies to do so.

4.1.5 Incentives on service quality and losses

Service quality

The transmission companies are obliged by their licences to meet technical standards with respect to network reliability. A significant deterioration in network performance would be likely to trigger an investigation by Ofgem, with the potential for significant financial penalties if the companies were found to have breached their licences. For end users to be cut off due to problems on the transmission network is rather rare. Following two large interruptions[127] on NGET's network in 2003, Ofgem carried out such an investigation and introduced the incentive scheme described below.

In addition to the technical standards of network planning and operation enforced by Ofgem, the network companies are also obliged to meet standards set by the government engineering inspectorate.

Following a major outage in 2003 Ofgem introduced an incentive scheme on network reliability: the TOs face a financial incentive to improve the reliability of their systems in terms of outages which lead to customers being cut off. The targets for the Scottish TOs are set in terms of the number of events leading to customers being cut off, and the target for NGET is expressed in terms of the volume of energy unsupplied.

[126] National Grid comments on Electricity System Operator Incentives, published as Annex 8 to the Ofgem review document, p. 8.

[127] Several hundred thousand customers were cut off. Although the interruptions lasted for less than an hour, many customers were affected for much longer. The blackout in London had a particularly large impact because it caused most of the city's underground railway system to be shut down, and many people were trapped in tunnels as a result.

Table 9: Reliability incentives[128]

	NGET	SPTL	SHETL
Maximum reward (% of revenue)	1	0.5	0.5
at	0 MWh	0 events	0 events
Deadband (zero penalty) from	237 MWh	8 events	10 events
to	263 MWh	10 events	12 events
Maximum penalty (% of revenue)	1.5	0.75	0.75
at	619 MWh	22 events	27 events

Notes
Figures from Ofgem

Ofgem has stated that it intends to refine its use of output incentives in regulating the TOs, and it has considered moving to a "penalty only" scheme for interruptions.

The costs of unreliability (in terms of the impacts on consumers) are also to be included in the assessment of the tradeoff between investment and operational cost under the SQSS, although there is no guidance given as to the methodology to be used.

Losses

Ofgem has also implemented an incentive scheme targeting losses. It sets a target for transmission losses (in TWh) as part of the SO incentives scheme. The SO is rewarded/penalised according to performance against the target, multiplied by an electricity price which is set ex ante (Ofgem considered indexing the price to wholesale prices, but did not do so). The current losses incentive price is £29/MWh, somewhat below current baseload forward prices. The cost of losses is included in the economic assessment of the tradeoff between transmission investment and operational costs under the technical engineering standards for transmission planning.

4.2 Transmission planning arrangements: key features

4.2.1 Transmission planning process

The transmission planning process is set out in Section D of the SO–TO code (the industry framework agreement which governs the relationships between the three TOs and the SO).[129] In theory, the basic idea is that the SO forms a view of the transmission capacity that will be required to meet the needs of users of the system over the coming seven years, and the SO and TOs together are responsible for ensuring that the network can deliver the necessary capacity. In practice the SO carries out modelling of power flows on the whole network on the basis of a forecast of demand growth and the location of new generators. The TOs then plan investments in their networks accordingly.

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[128] Taken from *TPCR: Final Proposals*, Ofgem December 2006, p. 66.

[129] *The System Operator Transmission Owner Code, version 2, revision 7* (available from the NGET website). Section D is on pp. D1 to D22.

The SO receives connection requests from new users, as well as annual capacity requests from existing users. Information from current and prospective network users feeds into the SO's forecast of demand for transmission capacity. The SO carries out technical modelling of the entire GB transmission system, under a framework set out in technical engineering standards, and generates "planning assumptions"—forecasts of power flows under all foreseeable conditions onto and off each TOs system over a seven-year planning horizon. This process culminates in the publication by the SO of a "seven year statement" (SYS), setting out in detail the SO's view of changes in generation and demand patterns, and the consequent changes in transmission capacity required. One of the functions of the SYS is to provide prospective network users (generators or very large consumers) with information on where transmission capacity will be available, and, especially, where new generation projects can be connected quickly because there is no need to carry out extensive system reinforcement before they can be connected.

The TOs are responsible for making sure that their systems meet the relevant technical engineering standards in force, under the power flow assumptions generated by the SO's modelling (the TOs have a licence obligation to plan and maintain an efficient network). The TOs use the results of the SO's modelling to decide when and where construction of new transmission assets might be required, as well as when during the year to carry out maintenance on the network. The SO–TO code requires the SO and the TOs to meet in order to co-ordinate network planning, and both the SO and the TOs are required to maintain investment plans showing proposed changes to their systems over the seven year planning horizon. However, in practice the SO plan is simply a collated version of the plans of the three TOs. The investment plans must include descriptions of planned works, details of consequent outages, and indications that users may be affected by planned works and/or may have to modify their own equipment. Any disputes between the SO and the TOs in respect of transmission planning are submitted to Ofgem for resolution.

The SO–TO code also requires the three companies to co-ordinate in respect of detailed construction planning on each new project, where required (for example, where investment is required in a connection between two TO systems, or where the timing of construction work is important because during the work network capacity will be temporarily reduced).

Transmission planning straddles the TO/SO divide. In principle, the planning activity could be carried out more-or-less entirely by the SO: the SO could carry out detailed system modelling, plan necessary expansion of transmission capacities, and direct the TOs what to do in terms of specific investments that would create the additional capacity. Alternatively, the planning activity could be carried out more-or-less entirely by the TOs: the SO would give the TOs a forecast of the evolution of load and generation (by location), and the TOs would decide when and where to invest. The GB arrangements under BETTA are very much towards the latter extreme, with the SO monitoring the TO plans. In practice the key investment decisions are probably made during the price-control process every five years (see below), and are the result of negotiation between Ofgem and the TOs.

Planning of additional interconnection between GB and neighbouring markets is outside the scope of the arrangements discussed here—there is no mechanism for regulated investment in interconnection. Any new interconnectors would be built on a merchant basis.

4.2.2 Implementation and cost recovery

As discussed above, the costs of the transmission network are not passed through directly to users: the companies' revenues are set in advance for five years, and the companies pay the costs of the network out of the allowed revenues, keeping any underspend and funding any over-runs.

Investment in expanding transmission capacity, as well as in maintaining existing capacity, is carried out and paid for by the TOs, and is funded from its price control revenues. Every five years the TOs must submit detailed capital expenditure plans to Ofgem as part of the price control process (outlined above). Ofgem and its technical engineering consultants review the investment plans and the associated expenditure forecasts to arrive at an allowed sum, which forms part of the price control settlement. Both individual projects and unit costs (e.g., cost per km of line) are subject to review. Once the price control is set, in principle the TOs keep any cost reductions and must fund any overspend during the price control period, and they are free to make tradeoffs, for example between capital expenditure on replacement and operational expenditure on maintenance (the price control applies to total revenue—i.e., there are no additional controls on how the revenue is used to meet different categories of cost). The companies can defer investment foreseen at the time of the price control provided that to do so is consistent with their licence and statutory duties—Ofgem retains powers to step in to require investment otherwise. If deferral of investment constituted a licence breach, for example because it was not consistent with maintaining an efficient transmission network, Ofgem could direct investment using its enforcement powers. The difference between actual and forecast expenditure is "reset" at the end of the price control period: actual not forecast capital expenditure goes into the regulatory asset base on which the companies will earn their cost of capital in the following price control period (subject to a regulatory test for reasonableness on unforeseen expenditure).

The capital expenditure forecasts in the price control process are obviously subject to considerable uncertainty, particularly when, as currently, large changes in demand for network capacity are forecast. Obtaining planning permission (from local government) for siting of wind farms is particularly difficult, due to the fact that the windiest places tend to attract protection for their landscape amenity value, thus making forecasts of new generation patterns very uncertain. For the 2007–12 price control Ofgem has attempted to deal with this uncertainty by funding a baseline level of capital expenditure. Once the volume of new connections to a TO's network exceeds a certain threshold, the price control revenue cap is automatically adjusted upwards by a pre-set £/MW multiplier of the amount of additional generation that connects. Thus the companies are not exposed to volume risk (once the baseline volume has been connected).

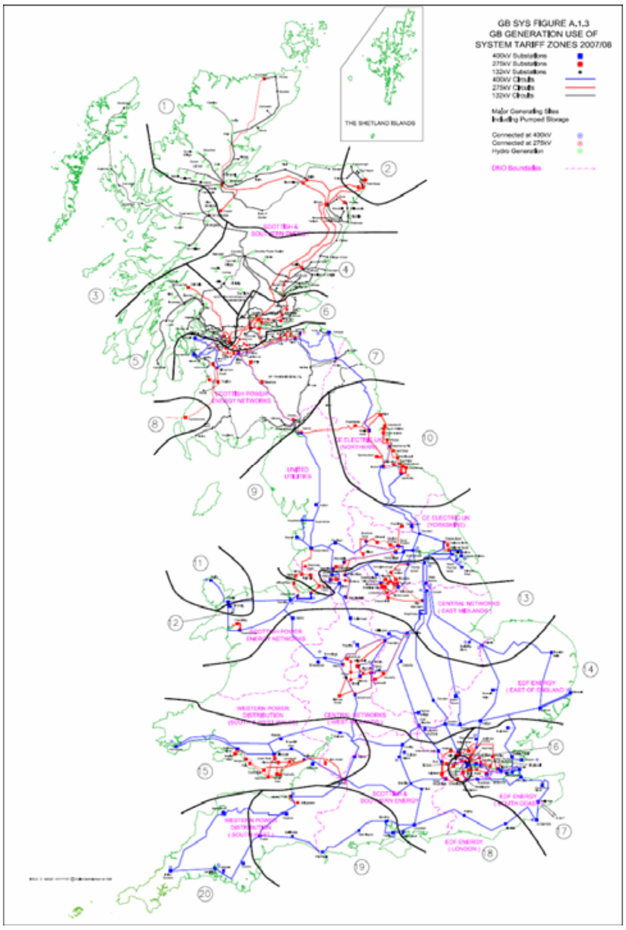
The TOs earn their cost of capital on all allowed network investment. It is common in other jurisdictions in Europe for network companies to be rewarded with a return above the cost of capital for "new" investment, or for investment which the regulator is particularly keen to see, perhaps because it is expected to enhance competition. A more sophisticated version of such arrangements has been used by Ofgem in the gas industry to allow the gas SO to earn a return above its cost of capital on investment in "additional" network capacity, provided that the capacity is paid for by users (i.e., the SO earns an extra return and also takes on extra risk: it is thereby incentivised to make accurate forecasts of users' future demands for capacity). Such a system has not been used to date on the electricity networks.

Tariffs

Users of the transmission network pay a one-off "shallow" connection charge—i.e., they pay for the equipment necessary to transport electricity between their site and the nearest point on the transmission network—and they pay annual "use of system charges". Where connecting a new user results in the need to reinforce the network, the costs of so doing are not charged to the new user but are spread over all users.

Charges for use of the GB transmission system are locational: the network is divided into zones, and use of system charges are set to reflect the long-run marginal cost of transporting an additional unit of electricity from each zone. Generators in Scotland pay more for their use of system than do generators in the south of England; demand in the south is charged more than demand in the North (in fact, generators in the south may pay negative charges). The charges are shown in Figure 11 and Table 10: the range is approximately –£10/kW/yr to +£20/kW/yr. This is quite a significant amount of money: for a generator operating 5,000 hours per year this is roughly equivalent to –5% to +10% of the electricity price.[130]

Figure 11: GB Generation Use of System Tariff Zones[131]



[130] Calculations based on an electricity price of £40/MWh.

Table 10: Generation Use of System Charges[132]

Generation Zone	Zone Area	Generation Tariff (£/kW)
1	North Scotland	21.590831
2	Peterhead	19.233718
3	Western Highland & Skye	19.858255
4	Central Highlands	16.436431
5	Argyll	14.677167
6	Stirlingshire	14.031535
7	South Scotland	13.017061
8	Auchencrosh	10.137439
9	Humber, Lancashire & SW Scotland	5.883070
10	North East England	9.253848
11	Anglesey	6.409118
12	Dinorwig	9.281586
13	South Yorks & North Wales	3.996719
14	MIdlands	1.973640
15	South Wales & Gloucester	-2.457186
16	Central London	-5.714694
17	South East	0.908414
18	Oxon & South Coast	-0.265230
19	Wessex	-4.098569
20	Peninsula	-8.568052

The existence of locational use of system charges, which broadly reflect the long-run cost of additional network capacity in that location, provide a means by which the tradeoff between investment in generation and transmission capacity can be made.

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131 *Seven Year Statement*, NGET 2007.

132 *Statement of Use of System Charges*, NGET 2007.

4.2.3 How transmission companies measure and are incentivised to respond to market needs.

The SO is required to publish and keep up to date the SYS (described above), which sets out its view of demand growth, where new generators will locate, where there will be additional investment in the network, and hence where there will be "opportunities" for new connections—i.e., where new generators would be able to connect to the network quickly, without having to wait for time-consuming network reinforcement. The SO takes a relatively narrow view in generating its forecast: for electricity consumption, it uses forecasts prepared by the electricity distribution networks, and, for new generators connecting to the network, it includes only those projects for which a connection agreement is already in place (entailing some financial commitment on the part of the generator). The SO is not required to make any wider forecast of likely demand for system capacity, and neither the SO nor the TOs have a direct financial incentive to speed up connections by carrying out system reinforcement before a firm connection request has been received.

Furthermore, there is no mechanism for prospective developers to secure rights to use the system: use of system charges are set annually, and Ofgem has stated that it is not clear that the current arrangements give existing generators permanent property rights over the use of the transmission system.[133]

The arrangements for access to the electricity transmission system can be contrasted with those for access to the gas system, where the SO is able to offer additional network capacity over and above that agreed with Ofgem at the price control. Long-term (17 years) rights to use the capacity are auctioned, and the SO is allowed to keep sufficient of the auction revenue to give it a rate of return on the capex required which is somewhat above the rate of return on the baseline capex. The SO is financially exposed if it fails to deliver contracted capacity because it has to compensate those who bought it.

Once generators are connected to the network there are strong incentives on the SO to ensure that sufficient network capacity is available, because the default is for connections to be firm: i.e., the SO has to pay generators if it cannot accept their output.

Although there is no direct financial incentive mechanism, the companies have licence requirements to plan an efficient system. In theory Ofgem could intervene if the companies did not bring forward investment plans in the face of a large volume of connection requests, or were very slow to carry out the necessary reinforcements.

4.2.4 Trading off transmission and non-transmission investments

In GB the trade-off between investment in transmission and other investment (e.g., in generation) is achieved by setting tariffs for use of the system which reflect the cost of using the system in that location (described above). Thus users are incentivised to take into account the value of scarce network capacity when deciding whether and where to connect to the system (and

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[133] *Transmission Access Review—A call for evidence for a review of transmission access*, Ofgem and DfBERR, August 2007, paragraph 2.6.

also in deciding whether to leave the system). There is no central planning undertaken to determine the optimal geographic mix of investment in transmission and generation.

The transmission companies have an obligation to connect: if the customer is prepared to pay the cost of connecting to the system, the connection has to be built. There is no explicit attempt to use cost–benefit analysis to determine whether it would be cheaper to reinforce the network or to build the generator in a location which did not require the network investment but was perhaps more expensive from the generator's perspective. The methodology for setting use of system charges goes some way towards encouraging an efficient outcome, but since use of system charges are set and paid for annually there remains some risk of assets being stranded, and it is possible that out-turn use of system charges will be different from the estimates taken into account by the generator in determining where on the network to locate.

The technical engineering standards (described below) allow for some tradeoff to be made between network investment and operational expenditure. The SO incentives encourage tradeoff between generation operating expenditure and network operating expenditure (i.e., the SO managing constraints by paying the TO to rearrange network outages, or by constraining generators on/off). As described above, the SO is exposed to the costs of managing constraints through a capped sharing mechanism. Because the cap has been reset every 12 months, it is possible for the SO to pay for extra costs associated with a TO rearranging planned maintenance of its network, but it is not possible for the SO to pay for network investment, if for no other reason than that the period of the incentive scheme is too short. An expanded SO incentive could perhaps be designed to encourage a tradeoff between network investment and SO operating costs. In addition to the cap on SO exposure through the scheme (currently a maximum of £20m),[134] there is a further mechanism to limit SO exposure by which it can apply for a direct pass through of costs associated with material unforeseen events.[135]

4.3 "Reliability" and "economic" investments

The distinction between "reliability" driven and "economic" transmission projects has been at the forefront of the policy discussion in the US, but has not been a significant issue in GB. To illustrate, consider two hypothetical investments: one driven by reliability issues, the other by a constraint.

Reliability

As a result of increasing demand, the flows over a particular circuit increase so that it no longer complies with the relevant reliability criteria (described below): if part of the circuit were to suffer an outage, the remaining part could no longer cope with carrying 100% of the flows

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[134] As noted above, the 2007/08 scheme has a +/–£10m cap/floor. Note that in past years the scheme has involved significantly higher exposure (e.g., the 2005/06 scheme involved a cap and floor of +£40m and –£20m respectively), but this has led to some tension between the GBSO and Ofgem.

[135] See, for example, *Determination under Special Condition AA5A Part 2(i), paragraph 12(a) of National Grid Electricity Transmission plc's Transmission Licence in respect of Scottish Constraints and CAP047*, letter published on the Ofgem website (September 25th 2006).

assumed for system planning that were shared before the outage. That part of the network is therefore no longer compliant with the technical engineering standards, and the relevant TO would be obliged to reinforce the network. The cost would be recovered through the price control.

Constraints

The assumed flows on a particular circuit as used for system planning are within the technical standards. However, the SO observes that in actual operation there is often a constraint on that line. It would therefore like the relevant TO to reinforce that part of its network, because the SO is liable for the costs of managing the constraint. The SO would raise the matter with the TO: the SO could not force the TO to invest, but it could object to Ofgem if the TO refused (for example because the project was not in the TOs price control CAPEX forecast).[136] Ofgem would require the investment if an economic case could be made for it, and if an economic case could be made the investment would be funded through the TO price control. We are not aware of any such dispute between the SO and a TO to date.

Since the SO resolves constraints by counter-trading rather than by market splitting, the costs of constraints are socialised. There are therefore fewer politically difficult distributional issues around the existence of constraints or plans to relieve them: all end users should always benefit equally from reductions in constraint costs.

4.3.1 "Reliability" investments

GB minimum requirements for reliability are laid down in the SQSS. This standard is a key input to the transmission planning process because it is the standard in accordance with which the electricity transmission owner licensees must "plan and develop operate the transmission system".[137] The criteria in the SQSS represent "the minimum requirements for the planning and operation of the GB transmission system".[138]

The GB SQSS uses deterministic measures such as "n – x" and maximum voltage changes. It defines requirements for each part of the transmission system: generation points of connection, the Main Interconnected Transmission System (MITS), and the Grid Supply Points (GSP) where demand is connected. The requirements are laid out in terms of:

- "Pre-fault criteria"—limits to be respected under "normal" conditions and in the absence of any fault on the system (e.g., voltages must remain within the pre-fault planning voltage limits); and

[136] CAPEX actually incurred which had not been foreseen and agreed as part of the price control would be incorporated into the regulatory asset base at the following price control, subject to a test as to whether the investment was efficient (ie, necessary or prudent).

[137] Electricity Transmission Owner Licence Standard Condition D3. The SQSS also plays a parallel role in setting operational rules for the GBSO.

[138] SQSS, para 1.5.

- "Post-fault criteria"—limits to be respected following a fault (under otherwise "normal" conditions). For example, there should be no loss of supply in the event of the outage of a single transmission circuit.

For example, Table 11 shows the minimum requirements following a "secured event" such as the loss of a single transmission circuit on connections to two or more demand points, both in normal conditions ("intact system") and in the event that there was already a single planned outage.

Table 11: SQSS Minimum planning supply capacity following secured events[139]

Group Demand	Initial system conditions	
	Intact system	With single *planned outage* ***Note 1***
over 1500 MW	**Immediately** *Group Demand*	**Immediately** *Group Demand*
over 300 MW to 1500 MW	**Immediately** *Group Demand* ***Note 2***	**Immediately** *Maintenance Period Demand* **Within time to restore *planned outage*** *Group Demand*
over 60 MW to 300 MW	**Immediately** *Group Demand* minus 20 MW ***Note 3*** **Within 3 hours** *Group Demand*	**Within 3 hours** Smaller of (*Group Demand* minus 100 MW) and one-third of *Group Demand*. **Within time to restore *planned outage*** *Group Demand*
over 12 MW to 60 MW	**Within 15 minutes** Smaller of (*Group Demand* minus 12 MW) and two-thirds of *Group Demand* **Within 3 hours** *Group Demand*	Nil
over 1 MW to 12 MW	**Within 3 hours** *Group Demand* minus 1 MW **In repair time** *Group Demand*	Nil
up to 1 MW	**In repair time** *Group Demand*	Nil

The basis for these detailed criteria is historical—they are essentially inherited from the pre-privatised industry, and do not derive from any detailed economic analysis. There are some differences in the standards that apply in Scotland relative to England & Wales: some reliability requirements are less rigorous in Scotland,[140] and this could be construed as reflecting a different balance of costs and benefits in Scotland, which is less densely populated and has more challenging terrain than England & Wales.

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139 SQSS Table 3.1, p. 14.

140 For example see SQSS Table 6.2, p. 25.

4.3.2 *"Economic" investments*

"Economic" investments can be identified as described above as investments to reduce the costs of persistent congestion. There is no requirement on the companies to do this explicitly (e.g., by means of specific studies), but the fact that the SO is exposed to constraint costs gives it an incentive to push for any such investments to be made.

The SQSS provide some high level guidance on the use of cost–benefit analysis to justify investments beyond those required to meet the minimum reliability requirements.[141] The guidance specifies that additional investment in equipment or purchase of services can be justified if the investment/service costs are less (on a net present value basis) than "the expected operational or unreliability cost that would otherwise arise". The guidance specifies that this analysis must take into account future uncertainties and the "expected duration of an appropriate range of prevailing conditions", but does not specify how this should be done.

Although generally rather vague, the SQSS guidance does specify that:[142]

> *the operational costs to be considered shall normally include those arising from:*
> - *transmission power losses;*
> - *frequency response;*
> - *reserve;*
> - *reactive power requirements; and*
> - *system constraints,*
>
> *and may also include costs arising from:*
> - *rearrangement of transmission maintenance times; or*
> - *modified or additional contracts for other services.*

With regard to unreliability costs, the guidance appears to require a probabilistic, VOLL-type analysis:[143]

> *the evaluation of unreliability costs expected from operation of the GB transmission system shall normally take account of the number and type of customers affected by supply interruptions and use appropriate information available to facilitate a reasonable assessment of the economic consequences of such interruptions.*

In practice, formal cost–benefit does not appear to play a central role in GB transmission planning, perhaps reflecting a concern that the complexities of modelling power systems would allow such analyses to be manipulated to favour a wide range of outcomes, (for example, through choice of electricity price scenarios over the lifetime of the transmission asset). Alternatively, it may be that the "reliability" standards are such that there are few or no opportunities for economic upgrades to be made—i.e., once the reliability standards have been met there may be few potential additional upgrades that would be justified on a cost–benefit basis. This may be

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[141] *Ibid.*, Appendix E, p. 51.

[142] *Ibid.*, E.2.4.

[143] *Ibid.*, E.2.6.

linked to the nature of the GB network, which is highly meshed and dense. In contrast, less meshed systems may more naturally fall into distinct zones that can meet reliability requirements with existing infrastructure, but where there may be an economic case for increasing interconnection between the zones.

4.4 Co-ordination of transmission planning

It is essentially the "top-down" planning and revenue determination and collection arrangements that promote coordinated planning. Since the entire GB transmission network is operated as a single system, there is no need for payments between transmission companies (for example, to compensate for transit flows). For example, suppose that connection of a new generator in the north of Scotland were to require investment by all three TOs in network reinforcement. The SO would receive the connection request and would model the impact on the GB system. The TOs would receive the results of the modelling, and would plan their network investment accordingly. The plans would feed into the TO price control process, and, if approved, would be funded in that way. The TO price control sets a cap on the revenues earned by the TOs, and the SO sets network use of system charges in order to recover the allowed revenues that it has to pay to the TOs. As a result of the reinforcement, the allowed revenues of all three TOs increase. The use of system charges therefore go up, and users on all three networks pay increased charges to the SO. The SO makes the necessary payments to the TOs.

In contrast, such a situation could have given rise to problems pre-BETTA, because under the old arrangements the SPTL network would in effect have been hosting a transit flow: the SPTL costs and allowed revenues would go up, but all of SPTL's revenues would have come from network users connected to the SPTL network. One of the drivers for implementing the BETTA arrangements was that pre-BETTA the connection between the Scottish and England and Wales networks was outside the regulated system: the interconnector was subject to contractual agreements between the companies that were funded on the Scottish side by the commercial (generation) interests. Ofgem had no mechanism to require expansion, or to fund it through regulated revenues.

Although the "top-down" arrangements limit the potential for conflict between TOs over planning, there is—as discussed above (4.2.3)—no direct financial incentive to encourage co-operation between the SO and TOs on transmission planning. Co-operation on transmission planning is entirely mediated by the regulatory framework: companies are required to co-operate rather than being rewarded for co-operation.

The limited possibilities for external interconnection mean that there is no significant need for international co-ordination of investment activity.

4.5 Evolution

The most significant step in the evolution of the current arrangements has been the separation of the TO and SO roles and the extension of a single area of system operation to the whole of GB. This change was driven by a combination of factors:

- a perception that the Scottish SOs could discriminate against new generation projects wishing to connect when allocating scarce network capacity, or could discriminate against third-party generators in operating the network;
- a desire on the part of regulators to extend wholesale market competition to Scotland (where prices were set on an administered basis); and
- a perception that the companies were unwilling/unable to agree to expand the interconnector between the Scottish SOs and England.

It is also interesting to note one element of "non-evolution". In the early 2000s Ofgem put forward a series of proposals that would have strengthened the market element in transmission planning, by instituting a system whereby the TO would build in respond to signals in long-term "auctions" for entry and perhaps also exit capacity.[144] Ofgem has introduced an analogous system for entry capacity on the gas transmission network. These reforms were unpopular with the industry, and have not been implemented. Criticisms of the reforms included that they were unnecessary (there was no obvious failing in the existing system), assumed away technical problems in defining capacity on a transmission network, and would lead to potential underbuild if the system required the TO to build only to meet certain demand rather than allowing it to build capacity on the basis of forecasts that took into account potential demand growth.[145]

Less radical changes may be in prospect: partly in response to the queue of connection requests, a review is currently underway into arrangements for access to the transmission network. In particular, the review is considering proposals under which connections would be financially firm before the necessary system reinforcement had been carried out, and proposals under which connections would be available more quickly but initially on an interruptible basis.

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[144] The term "auction" is probably a misnomer here: the mechanism envisioned was a kind of open season, where the TO announces its willingness to build new capacity for anyone willing to pay the long run marginal cost (in return for which they are given tradable firm long-term entry rights).

[145] In other words, if an "auction"/open season revealed demand for 500MW of additional entry capacity in a given zone, but it was relatively cheap to build 1,000MW and forecasts suggested that the additional 500MW would be used within a reasonable time frame then the TO should be able to build the additional capacity with the usual regulatory guarantees of cost recovery.

5 Continental Europe

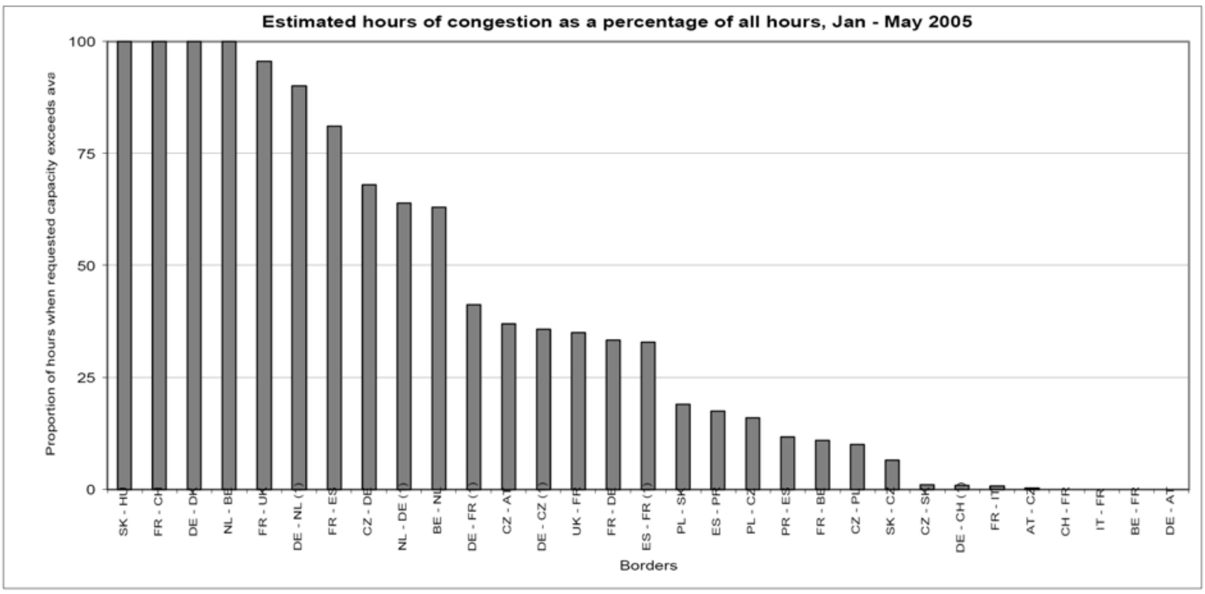
This section discusses evolving approaches to transmission planning in continental Europe (essentially, the UCTE system). At present there is no transmission planning process in place for the region—essentially all transmission planning is done at national level with no co-ordination other than voluntary bilateral agreements on cross-border lines (“interconnectors”). Nor does continental Europe form a single market area in any meaningful sense. We therefore do not adopt the same format as used above to describe other regions. Instead we describe the background and current EU proposals to establish a European-level approach to transmission planning and investment.

Historically the power systems of continental Europe were national in scope, typically run by a vertically integrated monopolist. National incumbents co-operated to some extent, including interconnecting, but the main purpose of interconnection was to provide additional security in the event of temporary supply-demand imbalances.[146]

5.1 Cross-border investment in Europe

The advent of liberalisation in the 1990s led to increases in cross-border flows, reflecting the existence of significant differences in costs and prices between EU Member States. This had two impacts. First, it quickly became apparent that existing interconnector capacity was inadequate to meet demand. Most cross-border interconnectors experience sustained congestion, as illustrated in Figure 12.

Figure 12: Cross-border congestion[147]



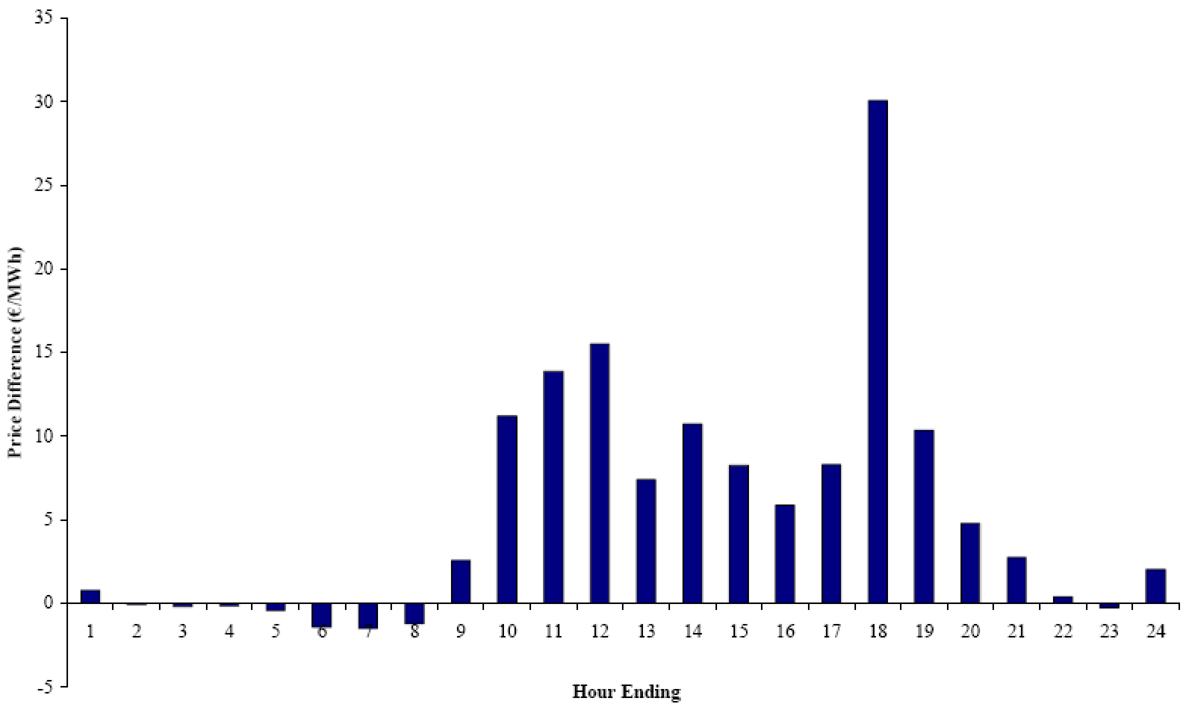
[146] *DG Competition Report on Energy Sector Inquiry*, European Commission, January 2007, p. 171.

[147] *Ibid*, p. 172.

Second, liberalisation led to significant "loop flows", creating congestion in sometimes unexpected places. This led to calls for compensation to TSOs in countries experiencing such flows, notably Belgium (increased exports that contractually go from France to Germany appear to have led to significant increases in physical flows on the Belgian high-voltage system).

The presence of persistent congestion at national borders in Europe reflects underlying differences in costs and probably also in the level of competition in different Member States. Cost differences arise for a number of reasons. For example, national policy in the Netherlands for many years encouraged the use of natural gas for power generation, and natural gas prices in Europe in recent years have been rather high relative to other fuels, leading to a high level of imports and congestion on the Dutch borders (in particular, the Dutch–German border, as illustrated in Figure 13).

Figure 13: Hourly price differences, Netherlands vs Germany, 2004–05[148]



Source: APX, EEX.
Note: A positive price difference indicates the price in the Netherlands exceeding the price in Germany.

Differences in the level of competition may also explain some of the price differences, with higher prices in countries where wholesale markets are less competitive. Most national markets in the EU are highly concentrated in terms of ownership of generation, as shown in Table 12, making competition difficult without significant reliance on cross-border trade.

148 *Factors affecting geographic market definition and merger control for the Dutch electricity sector*, study for the Dutch competition authority (NMa) by *The Brattle Group*, 2006.

Table 12: Concentration of generation ownership[149]

	Number of companies with 5% share of production capacity	Share of largest 3 producers
Austria	5	54%
Belgium	2	95%
Denmark	10	40%
Finland	10	40%
France	1	96%
Germany	5	72%
Greece	1	97%
Ireland	2	93%
Italy	5	65%
Luxembourg	1	88%
Netherlands	4	69%
Portugal	3	76%
Spain	3	69%
Sweden	10	40%
UK	8	39%
Norway	10	40%
Estonia	1	95%
Latvia	1	95%
Lithuania	3	92%
Poland	7	45%
Czech Rep.	1	76%
Slovakia	1	86%
Hungary	7	66%
Slovenia	3	87%

In response to the perceived need for increased interconnection the EU introduced a number of measures.

- European legislation introduced in 2003[150] requires TSOs to use the "congestion rents" arising from the allocation of congested interconnector capacity either to fund increases in available capacity or to reduce tariffs.
- The same legislation also makes it possible for merchant interconnectors to be exempted from regulation of both access requirements and tariffs.[151]

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[149] Commission Staff Working Document, *Report on Progress in Creating the Internal Gas and Electricity Market: Technical Annex to the Report from the Commission to the Council and the European Parliament*, 2005.

[150] Regulation (EC) 1228/2003 of the European Parliament and of the Council of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity.

- There was also a political commitment to ensuring that each Member State should have a minimum level of interconnection equal to 10%.[152]
- The Commission adopted a "priority interconnection plan", providing some (small) funding for certain interconnections, together with mechanisms intended to lessen political and bureaucratic obstacles for a small set of key "strategic" projects.

Despite these measures the level of investment in new interconnection has been very low. A 2006 report from the European Commission concluded that:[153]

> *Amounts invested in cross-border infrastructure in Europe appear dramatically low. Only €200 million yearly is invested in electricity grids with as main driver the increase of cross-border transmission capacity. This only represents 5% of total annual investment for electricity grids in the EU, Norway, Switzerland and Turkey.*

The same document quoted IEA projections for total grid investment needs in the EU between 2001 and 2010 at €49 billion.

The measures listed above therefore appear to have proved quite ineffectual. An investigation into the EU energy sector undertaken by the European Commission estimated that only about a quarter of congestion revenues were re-invested in increasing interconnection capacity. In the case of Germany it noted that "[i]n the period 2001 to 2005 three German TSOs managing interconnectors generated congestion revenues of [400–500] million Euro. Of these revenues only [20–30] million Euro were used to reinforce/build new interconnectors...all TSOs maintained that the remaining revenues were used to reduce the transmission tariffs."[154]

There has been vigorous debate over the lack of investment in interconnection (which is generally acknowledged to be a problem, although very little rigorous cost–benefit analysis has been undertaken). Proponents of liberalisation have argued that it is due to intentional under-investment by vertically integrated incumbents looking to minimise the risk of competition. The incumbents have focused instead on the difficulty of obtaining planning permission for new lines, and the lack of regulatory underpinning for cross-border investments.

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[151] Article 7 of Regulation (EC) 1228/2003 of the European Parliament and of the Council of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity. In practice this has been used for subsea interconnectors, since it is hard to fit a merchant interconnector model into the highly meshed onshore system of continental Europe.

[152] See conclusion of the European Council meeting in Barcelona, March 2002.

[153] Communication from the Commission to the Council and the European Parliament: Priority Interconnection Plan {SEC(2006) 1715} {SEC(2007) 12}, 2006.

[154] *DG Competition Report on Energy Sector Inquiry*, European Commission, January 2007, pp. 179–80.

5.1.1 Criteria for assessing cross-border transmission upgrades

TSOs in Europe use the same kinds of criteria as most other TSOs studied in this report to assess transmission upgrades within their systems. The European TSOs' trade association (ETSO) summarises the situation as follows:[155]

> *Historically two approaches have been used as a means of identifying whether or not a transmission system is adequate i.e. a deterministic approach to comply with security criteria and a cost–benefit approach to compare costs of incremental transmission investment with benefits provided by the investment (also taking account of costs avoided e.g. constraint costs). In most countries in Europe the two approaches are used together: initially an assessment is made using the deterministic approach and then it is backed-up by using a cost–benefit approach. For the deterministic approach models and procedures exist, however, the approach to evaluate the cost benefit may differ widely, and is subject to regulatory approval.*

However, the situation is quite different for cross-border infrastructure. The same report notes that

> *[F]or cross-border investments no systematic approach has been derived yet, and in most cases cross-border investments are not managed under an agreed set of criteria and objectives. The extension of the intra-country approaches to cross-border investment would seem the obvious solution, but in order to do so the following changes would be necessary:*
>
> - *agreements, among the regulators, on the allocation principles for the costs incurred by the TSOs for interconnection investment;*
> - *regulatory mechanisms, such as TSOs incentive payments or increased regulated return on investments in case of the development of new interconnection infrastructures;*
> - *remuneration methodologies for intra-country transmission investment that increase interconnection capacity;*
> - *solutions which encompass required investment by a third country to upgrade interconnection capacity between two other countries;*
> - *arrangements which permit merchant developments and allows those developers to retain congestion rents as the reward for taking the investment risk in the first instance.*

5.1.2 The Inter-TSO Compensation mechanism (ITC)

As the quotation above suggests, one problem in Europe is the absence of a suitable mechanism to compensate TSOs for investments that benefit parties outside their own area. Since 2002 there has been in place a candidate mechanism, the Inter-TSO Compensation mechanism

[155] *ETSO Position Paper on Roles and Responsibilities of TSOs and other actors in Cross-Border Network Investment*, July 2006.

(ITC). This mechanism is an agreement backed by legislation that decides the size and allocation of a compensation fund according to a technical methodology arrived at by agreement among the TSOs. The relevant legislation[156] requires that:

- *Transmission system operators shall receive compensation for costs incurred as a result of hosting cross-border flows of electricity on their network*
- *The compensation shall be paid by the operators of national transmission systems from which these cross-border flows originate, and systems where those flows end*
- *The magnitude of cross-border flows hosted and the magnitude of cross-border flows designated as originating and/or ending in national transmission systems shall be determined on the basis of the physical flows of electricity actually measured in a given period of time*
- *The costs incurred as a result of hosting cross-border flows shall be established on the basis of the forward looking long-run average incremental costs, taking into account losses, investment in new infrastructure, and an appropriate proportion of the cost of existing infrastructure, as far as infrastructure is used for the transmission of cross-border flows.*

The legislation also gives the European Commission the right in principle to determine the mechanism (rather than relying on voluntary agreement among the TSOs).

In practice, however, the ITC has proven a source of great difficulty. Because it creates winners and losers (and the sums of money involved are quite substantial)[157] it is difficult to get voluntary agreement. In 2007, for example, agreement on the 2007 mechanism was not announced until half way through the year.[158] The obvious way to overcome this problem would be to have an over-arching body make the decision.

However, the obvious over-arching body, the European Commission, lacks the technical capacity to design a mechanism of this nature. Responsibility has therefore been left with the TSOs, despite the difficulty of obtaining agreement and despite also quite intense technical criticism from independent observers of the methodology they have adopted.[159]

[156] Regulation (EC) 1228/2003 of the European Parliament and of the Council of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity.

[157] In 2006 the total ITC fund was €395 million: see *ETSO Proposal for the 2006 CBT Mechanism*, 2005.

[158] ETSO Press Release: *Inter-TSO Compensation Mechanism for 2007*, 15 June 2007.

[159] See for example O. Daxhelet and Y. Smeers, *Inter-TSO Compensation Mechanism*, 2005, mimeo.

5.2 Proposals for Reform

The European Commission has recently issued proposals for wide-ranging reforms to the framework for EU energy markets. From the perspective of this study they main elements are as follows.

1. EU TSOs would be required to co-operate through a legally mandated European Network of Transmission System Operators ("ENTSO").[160]
2. Among many other tasks, ENTSO would "publish a Community-wide 10-year network investment plan every two years. The investment plan shall include the modelling of the integrated network, scenario development, a generation adequacy report and an assessment of the resilience of the system. The investment plan shall, in particular, build on national investment plans …[and] identify investment gaps, notably with respect to cross border capacities."
3. The draft investment plan would be subject to (limited) oversight by a proposed European level regulatory-type body, the "Agency for the Co-operation of Energy Regulators".
4. TSOs would also be required to cooperate at "regional level". In practice the EU is divided into a number of regions, each of which is reasonably well connected internally, but has limited connection with neighbouring regions (e.g., the Iberian Peninsula, Italy, Benelux–France–Germany). The intention here is for each region to develop joint planning processes.
5. As part of this regional co-operation, TSOs would be required to publish a regional investment plan every two years.
6. Secondary legislation would incorporate the ITC mechanism into national tariffs, and also provide for "appropriate and efficient harmonised locational signals at European level".

At the date of writing the exact import of these reforms remains vague. However, there are some points of interest for this study.

- There is a clear recognition of the need for some level of co-ordinated planning for investment. It is likely that, at least at first, the "10-year network investment plan" comprises an assessment of overall needs, based on load and generation forecasts and some power flow modelling, combined with perhaps some recommendations on the need for new cross-border interconnectors. Under this model the plan would not make any proposals for investments within national systems, beyond possible recognition that its proposals for cross-border investment might create a need for system reinforcement internally. Nonetheless, it would be a significant advance from the current situation.

[160] *Proposal for a Regulation of the European Parliament and of the Council Amending Regulation (EC) No 1228/2003 on conditions for access to the network for cross-border exchanges in electricity*, issued by the European Commission on 19 Sept 2007.

- The legislation does not require ENTSO to develop a specific methodology for assessing transmission investments (either in terms of reliability or economics). However, it is likely that this would be done in due course.

The recognition of the need for locational pricing at EU level is a significant change in policy. Previously the European Commission had supported a move to uniform transmission tariffs across Europe, on essentially political grounds. However, there are strong economic grounds for introducing EU-wide locational signals, particularly in light of the massive investment in renewable energy that is required to meet ambitious new targets for renewables.

ABBREVIATIONS

AESO	Alberta Electric System Operator
BETTA	British Electricity Trading and Transmission Arrangements
BM	Balancing Mechanism (GB electricity balancing market)
CAISO	California Independent System Operator
CPUC	California Public Utilities Commission
DoE	US Department of Energy
ETSO	European Transmission System Operators
FERC	US Federal Energy Regulatory Commission
FTR	Financial Transmission Right
GBSO	Great Britain System Operator
IEA	International Energy Agency
ISO	Independent System Operator
ITC	Inter-TSO Compensation scheme
LMP	Locational Marginal Pricing
NERC	North American Electric Reliability Corporation
NGET	National Grid Electricity Transmission (GB SO and TO in England and Wales)
PJM	a US ISO covering all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia
PUC	Public Utilities Commission (US state regulators)
RTO	Regional Transmission Organisation
SHETL	Scottish Hydro-electric Transmission Ltd
SO	System Operator
SPTL	Scottish Power Transmission Ltd
SQSS	System Quality and Security Standard
TEAM	Transmission Economic Assessment Methodology
TO	Transmission Owner

TSO	Transmission System Owner/operator
UCTE	Union for the Co-ordination of the Transmission of Electricity
WECC	Western Electricity Co-ordinating Council (part of NERC)

ABOUT THE AUTHORS

This report was prepared for the Australian Energy Market Commission by Boaz Moselle and Toby Brown, with advice from Johannes Pfeifenberger and Greg Basheda. Boaz Moselle is a Principal at *The Brattle Group*, focussing on energy market analysis, competition economics, and network regulation. Toby Brown is an Associate in Brattle's Brussels office, also working in energy and competition. Johannes Pfeifenberger is a Principal in Brattle's office in Cambridge, Massachusetts, and Greg Basheda is a Senior Consultant in Brattle's Washington DC office.