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Incentives for an Adequate, Economic and Reliable Swiss Transmission Grid.

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Authors:

Paul Twomey, Faculty of Economics, University of Cambridge
Karsten Neuhoff, Faculty of Economics, University of Cambridge
David Newbery, Faculty of Economics, University of Cambridge

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Principal:
Swiss Federal Office of Energy SFOE

Contractor:
Faculty of Economics, University of Cambridge

Authors:
Dr. Paul Twomey
Dr. Karsten Neuhoff
Prof. David Newbery

Accompanying group:
Dr. Rainer Bacher, Head of Grids Section, Head of the Grids and Systems Research Division, SFOE
Michael Bhend, SFOE
Dr. Peter Ghermi, SFOE

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Swiss Federal Office of Energy SFOE
Mühlestrasse 4, 3063 Ittigen - Postal address: CH-3003 Bern
Tel. +41 31 322 56 11, Fax +41 31 323 25 00 - contact@bfe.admin.ch - www.admin.ch/bfe

Table of Contents

Executive Summary

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As Switzerland moves towards a more liberalized and competitive electricity market, an essential task of policy makers will be to ensure that incentives are in place for the construction, maintenance and operation of adequate, economic and reliable transmission infrastructure. As well as continuing to serve the domestic market, the location of Switzerland within the centre of Europe also means that policy should embrace opportunities in servicing the developing European Internal Market by providing transit and other services. In developing such policy, however, theory and experience with liberalized electricity markets has demonstrated that both the regulated and merchant approaches for supporting transmission investment have a number of difficulties that can lead to problems such as suboptimal investment, productive inefficiencies and market power exploitation. The aim of this report is to review the key economic issues, problems and potential solutions that the SFOE and any future Swiss regulator may face as Switzerland embarks on its reforms of the electricity sector and the EU takes further measures to create the Single Electricity Market. This report is part of a potentially larger project, the key output to be a framework and toolkit to address the different means of encouraging appropriate transmission infrastructure development.

Economic Evaluation of Transmission Investment Proposals

At present the SFOE evaluations of transmission investment proposals are primarily focused on technical, environmental and reliability criteria. A future Swiss regulator may wish to make more detailed examination of the economic consequences of interconnection proposals.

An independent evaluation of the economic impacts for the Swiss society will become increasingly important to ensure that operational and investment decision of Swiss network operators are aligned with society's interest even as network control moves increasingly to private and foreign ownership.

There are a number of objectives which the Swiss cantonal and central government might pursue in its policy for transmission investment. These can include resolving bottlenecks, ensuring security of supply for Swiss and European customers, facilitating the value maximising utilisation of flexible hydro generation capacity, increasing the level of competition, facilitating profitable transits for neighbouring countries and contributing to the Swiss and European objective of reducing CO_2 emissions. Experience to date suggests that there are serious difficulties in anticipating the impact of investment projects on any of these objectives.

Regulated Transmission Investment

Under the new Law on Electric Power Supply (LEPS) to be introduced in Switzerland, transmission investments – including interconnectors - will be funded under a regulated tariff system. In this approach the transmission owner proposes a capacity expansion which needs to be approved by the regulator.

There are a number of good reasons for recommending this development: it represents a short step from the pre-liberalized systems and is relatively easy to introduce in the short term; monopoly rents may be regulated, and the centralized and regulated nature of the process provides a relatively secure and controlled environment in which infrastructures can be built.

The extensive international experience with regulated transmission investment does, however, also point to some difficulties with this approach:

- If the regulated rate of return is mis-estimated and set too low the TSOs may be reluctant to propose new projects or upgrades, thus creating risks to security of supply. Conversely, if the TSO sets the allowed rate of return too high or the TSO forecasts greater than realized demand for capacity, there may be excessive (and uneconomic) investment and customers will pay too much.

- These risks are amplified by special interest groups lobbying the Government, TSOs or regulators.

- Customers bear the risks of inappropriate or inefficient investment rather than those who proposed and built the line.

For transmission interconnection between regions a number of further difficulties can be identified:

- Vertically integrated utilities have poor incentives to invest in interconnector capacities because that may increase competition within their own generation markets.

- Regulatory uncertainty can impede investment by regulated private transmission companies where the investment can affect the TSO's revenues (as in the case of trading over interconnectors). The argument is that a regulator cannot credibly commit to "allow high profits" if *ex post* the state of the world turns out to be good, but may be less concerned if the company suffers losses on this investment.

- Public-choice conflict. If permission to build a line is required on the two ends of an interconnector, the authorities would each need to be convinced that the extra charges needed to finance a regulated investment can be justified on cost-benefit criteria as benefiting their jurisdiction. This may not always be the case. Requiring economic approval allows other goals to enter the discussion or can easily be abused.

A further problem in Switzerland occurs as a result of the current European inter-TSO compensation scheme. According to Etrans, there are Swiss lines which are carrying large fractions of transit flows that are arguably not receiving an appropriate level of financial compensation. In such cases the shortfall between the compensation and the relevant transmission costs will be borne by Swiss grid users (via the transmission charges). Future interconnectors which were inadequately compensated by the inter-TSO compensation scheme would then be unattractive to Switzerland. Merchant lines that were properly charged for their domestic use of the grid would be an attractive alternative, and provide an additional motive for encouraging merchant lines (provided they are properly charged for their use of the Swiss network).

There are sound arguments for unbundling transmission from generation to prevent distortions that arise when the TSO favours its own generation or deters entry by other suppliers. Ideally such unbundling would be of ownership, but even if initially it is only possible to create legally separate transmission companies (under the ownership of a group that also owns generation), it will still be necessary to devise a system of setting transmission charges. The choice of charging system and implied horizontal transfers between countries and vertical transfers between transmission levels will have direct implications for the economics of interconnector investments, and possibly also for power flows and hence the demand for transmission investment (and the location of new generation). Transmission investors will therefore need guidance on what form of transmission regulation to expect, and its design will therefore be important for guiding efficient system development.

Merchant Transmission Investment

With merchant transmission investment (MTI) it is left to market participants to identify, propose, finance and build new transmission lines. The investment is remunerated by the opportunity to arbitrage price differentials between different locations of the network. So far there have only been a limited number of realised projects, mainly in Argentine, Australia and some smaller scale projects in the USA. In Europe the first transmission line to be constructed as a merchant transmission line is likely to be EstLink between the Baltics and Finland. Various options for merchant based transmission investment between Switzerland and neighboring countries have been discussed.

There are a number of challenges for the merchant transmission investment model that might imply that the investment volume is too low:

- ***Economies of scale and cost-recovery***. Economies of scale typically dictate large capacity lines, but this is also likely to result in low or zero price differentials across the line and thus undermine the profitability of building at an efficient scale or even at all.

- ***Loop Flow Effects*.** In a meshed AC network a new line can be privately profitable but social detrimental due to loopflow effects.

- ***Free-riding Problem.*** If participants in regions connected by a line can benefit from a merchant line regardless of whether they contribute to the construction then there can be a free-riding problem and possible underinvestment.

- ***Investment deterrence.*** Anticipation of future regulated investment might undermine the investment incentive for unregulated investment and thus deter or delay that investment.

- ***Market Power.*** Transmission contracts can give rise to market power concerns.

Policy makers should also be aware that merchant investments may lock in the current institutional and regulatory environment (e.g. decentralized power exchanges) which may make changes to future regulatory intervention difficult.[1]

In the light of these difficulties there are a number of specific issues that a future Swiss regulator should be prepared to answer in relation to setting up a merchant transmission line scheme:

- ***Ownership.*** Should a regulated TSO on either side of the unregulated transmission line be allowed to be an owner of the line?
- ***Third party access provisions.*** *Should the line owner be allowed to be a user of the line or should this be fully separated? Should the line owner be free to determine who will be entitled to use the line, or should a non-discriminatory open-access regime apply?*

- ***Must-offer Provision.*** Should the regulator put in place a must-offer provision that requires the line owner to offer all capacity?

- ***Capacity Reservation.*** Should at least part of the capacity of a merchant line be reserved for the short-run spot market instead of selling all capacity in long-term contracts?

- ***Option to Convert to Regulated Revenues.*** Should the regulator allow a merchant investment the option to convert into a regulated line and if so on what terms (and should these be specified in advance)?

Theory provides some tentative conclusions but the question needs further research.

In establishing a dividing line between merchant and regulated lines we suggest:

- Allowing MTI in cases where the net benefits of a regulated line are unclear, provided that the MTI does no (uncompensated) damage to existing network users and provided that this does not restrain future market or network design;

- Allowing MTI where there are net benefits that the TSO for various reasons is unable to secure or is unwilling to invest for other (often market power) reasons;

- Where distant new generation needs new transmission investment to access the grid, then these can be included in the generation project (most applicable to e.g. off-shore wind power);

[1] Decentralised power exchanges are set up by traders (although sometimes financed by TSOs) and charge fees to cover their costs. Their use is not compulsory, and they typically only handle a small fraction of final demand (2-20% if Nordpool iis excepted).

And finally, considering the case for restricting regulated investment to those cases where the benefits and/or costs of efficient network expansion are so diffuse that they cannot be properly captured by MTI, and otherwise ensuring that the system of grid access and use-of-system charging as well as payments for contributions to security and other ancillary services are such that simple transmission investments can be left to MTI. This option relies on the set of grid access and usage charges being accurately set, which sets a very tough standard that may not be realistic in the short run.

Congestion Management

Switzerland has been following the rest of Europe in the development of bilateral auctions with neighbouring countries. Nevertheless, it is clear that there remain unrealised gains from better management of cross-border flows, but disagreement on the ultimate goal and the means to reach it. Market splitting has attractions, as do nodal pricing. **[There may be some useful evidence from the sector inquiry to rehearse here.]**

Inter-TSO Compensation

Inter-TSO compensation arrangements have evolved under the EU-stimulated Florence Process, and there is now a workable model that overcomes the obvious inefficiencies of earlier solutions, particularly the pancaking of rates at each TSO border. The determination of the best method for determining cross-border compensations reflects a tension between the simple and auditable average participation rule or the theoretically more elegant but computationally more demanding marginal participation rule. As the choice of market design for congestion management, transmission pricing and cross-border charging will affect the economics of any transmission investment (merchant and regulated), there is some urgency to clarify the likely future methodologies to be adopted. It should be noted that neither rule rewards the increase in security and reliability that additional links may provide.

The outline of this report is as follows. Section 2 begins by identifying the set of benefits and costs of transmission (and particularly cross-border interconnections). Recognizing the value underlying a transmission investment is clearly useful for the purposes of identifying possible sources of financial backers of a project. We look at the appraisal techniques that are employed in quantifying them and briefly discuss the issue of a ‘regulatory test’, which may be employed by a regulator as part of a transmission project approval process. Section 3 examines the various approaches to regulating and rewarding infrastructure development. At the most simplest level the primary division is between regulated approaches and market-based (or merchant) approach. The comparative advantages and disadvantages of each approach are discussed. Section 4 examines the current state of European transmission regulation and looks at relevant market developments. Section 5 turns to Switzerland and after briefly discussing the market and regulatory environment discusses how the different approaches to financing transmission investment could fit into the Swiss requirements. Section 6 provides conclusions and recommendations.

1 Introduction

In response to the needs of liberalised markets and the stresses in transmission systems revealed by a series of high profile blackouts in the US and Europe, various bodies are now grappling with the problem of how to improve the operation and stimulate the extension of the transmission network. In the US, the Federal Energy Regulatory Commission, FERC, has encouraged the adoption of a Standard Market Design and encouraged the creation of larger Regional Transmission Organisations to facilitate efficient trade over wider areas and to encourage more transmission investment. In Europe, under prompting from the European Commission, the European TSOs are engaged in the Florence Process to develop rules for the better management of interconnectors and cross-border trade. The European Commission released a *Regulation on cross-border exchange* in 2003[2] which addresses these topics, and continues to publish guidelines for these regulations, although as at the time of writing these guidelines were only in draft form.[3]

In addition to these more visible inter-TSO issues of cross-border trade, investment, and the management of security, within each TSO's jurisdiction the transmission network is called on to perform an increasing role in supporting an effectively competitive power market. Both cross-border and internal transmission management demands raise a whole set of complex issues.

The objective of this report is to systematically examine the issues surrounding the regulatory and financial compensation schemes for electricity transmission infrastructure investment to see how they may apply to the Swiss electricity system. A particular emphasis will be upon cross-border interconnectors and the potential for merchant transmission investment (MTI). Merchant transmission investment is typically undertaken by a third party and is funded by trading between differently priced markets or zones. MTI contrasts with traditional regulated transmission investment which relies on regulated tariffs as remuneration. Although considerable scepticism has been expressed about the role of MTI within regulated jurisdictions and even for bilateral links between neighbouring countries, Switzerland is in a rather different position of being a transit country. MTI that allows transit benefits the exporting and importing countries, but not necessarily Switzerland. MTI investments force those benefiting from the transit interconnectors to pay the full cost and would appear to avoid unnecessary costs falling on Swiss consumers. MTI raises a whole new set of questions that the regulator and policy makers must face. This report is part of a potentially larger project, the key output to be a framework and toolkit to address the different means of encouraging appropriate transmission infrastructure development.

In many countries the case for MTI for interconnectors has attracted interest because of concerns that incumbent transmission system operators will underinvest in such links (or even actively oppose them). An important part of this report is to reflect on the nature of merchant lines and the different regulatory schemes that can be employed to utilize their potential. This will include the important questions of their effect on competition, the desirability or otherwise of ownership restrictions, third-party access regimes, must-offer provisions, and the feasibility of the co-existence of regulated and unregulated (merchant) schemes.

However, it is important to discuss both the merchant and regulated transmission approaches together because the evaluation of each approach should not be against some theoretical benchmark but against each other. The practical choice involves a tradeoff between *imperfect* markets and *imperfect* regulation (Hogan, 2003; Littlechild, 2005).

For each approach, there is currently no first-best solution available that guarantees perfect economic efficiency in transmission investments. In this report we will discuss many of the difficulties with each approach in order to establish where the line should be drawn between merchant and regulated transmission investment.

[2] Regulation (EC) No 1228/2003 of 26 June 2003 on conditions for access to the network for cross-border exchanges in electricity, OJ. L176/1, 15.07.2003, European Commission, Brussels. The regulation entered into force on 1 July 2004.

[3] See also ERGEG's conclusion document *The creation of Regional Electricity Markets* at http://www.ergeg.org/portal/page/portal/ERGEG_HOME/ERGEG_DOCS/ERGEG_DOCUMENTS_NEW/ELECTRICITY_FOCUS_GROUP/ and the ERGEG web site.

The current legal and regulatory framework for electricity in Switzerland involves a complex interplay between all three levels of government (federal, cantonal and municipal). The most important reform elements are the creation of an independent regulator and system operators, and the adoption of regulated third party access. A new reform package is being debated by Parliament and there is cautious optimism that the reforms will be implemented. For present purposes we will assume that this will be the case.

Switzerland, while not part of the European Union, cannot avoid being affected by EU plans for a single competitive electricity market. Hence this report will examine a number of aspects of the current and prospective wholesale electricity markets in the EU. From a European Union perspective, the encouragement of appropriate new transmission infrastructure is a high priority in the development of an effectively competitive single electricity market. However, market and infrastructure developments that may assist in the overall European plan may not necessarily all be in the interests of Switzerland.

Before liberalization, the electricity supply industry in the EU was typically characterized by large vertically integrated monopolies who co-ordinated both production and transmission of electricity. They planned and operated the electricity systems to optimise investment in and the location of both generation and transmission links, taking account of national costs and benefits (and to some extent bilateral agreements with neighbours). As this coordination was purely national there was no guarantee that the system was developed in the most efficient way from the European perspective. Liberalization that separates generation from transmission may impede this kind of national coordination, although it offers the prospect of the more efficient use and development of wider area systems. The resulting challenge to achieving these wider benefits is to devise methods that allow many competing generators and suppliers to indicate their need for efficient electricity transmission in the short and long term, and to assess how TSOs can best respond to such requirements within some form of regulatory regime.

As will be discussed below, to the extent that the Single European Electricity Market becomes a reality and markets are more effectively integrated, market prices might be expected to become more uniform across countries. This may threaten much of the commercial attraction of merchant interconnectors without specific mechanisms to ensure that continuing benefits are recompensed. If merchant lines are perceived to be too risky or commercially unattractive, then it is likely that TSOs will need to finance regulated interconnectors (and associated reinforcements within their grids) to facilitate bilateral cross-border trade (and reduce domestic market power). The key question facing policy makers and regulators is how investments in transit countries like Switzerland, which under some circumstances might mainly benefit neighbors, should be financed and how beneficiaries should be charged for their use in ways that do not inhibit socially beneficial trade. This is an interesting and challenging problem in public good mechanism design, complicated by the meshed nature of the network and the problems of cost attribution caused by Kirchoff's Laws. We see this as a large part of the research agenda, as without a clear concept for the construction and charging of regulated interconnectors, it will be difficult to see how merchant interconnectors would be financed, given the considerable uncertainty caused by the threat of investment in competing but regulated interconnectors.

This document is only an initial investigation pending more detailed analysis aimed at developing a more comprehensive framework. Such a framework could provide a more certain regulatory environment for prospective investors in transmission. As many commentators have pointed out, one of the major obstacles to the development of new cross-border transmission investments is the uncertainty (and partly regulatory uncertainty) about obtaining an adequate return on investment.

2 Benefits and Costs of Transmission Expansion

Building a transmission line creates a range of costs and benefits. Identifying such costs and benefits is useful for (1) establishing the social and commercial value of a line and (2) identifying potential investors who have an incentive to undertake a transmission project. As we will see, some benefits and costs are private and can be captured by the associated users. In such cases, the allocation of appropriate property rights may enable private financing, where the revenue or value of the transmission line is captured by these property rights. Other benefits and costs may be of a public nature and may raise difficulties for designing private funding arrangements such that the full costs and benefits are fully incorporated into the investment decision. In such cases, the use of regulated tariffs which socialize the costs of the transmission investment may be the best route, although as a general regulatory principle, the charging system should attribute costs and benefits to those who cause them as closely as possible.

2.1 Benefits

There are a number of sources of value from building a new transmission line. These include:

- *Avoidance or deferral of investment in generation capacity.* Peak capacity requirements can be reduced with greater transmission. This can be seen most easily with an interconnector between two different regions in which demand patterns differ. Also to the extent that demand and supply evolutions are not perfectly correlated in neighboring regions, the uncertainty about joint future reserve margins will be lower, thus reducing the need for some generation.

- *Savings in fuel and operating costs through substituting cheaper generation for more expensive generation*. Connecting all electricity generators through the transmission system allows the use of the cheapest generation available, no matter where it is.

- *Saving in cost of frequency control and operating reserve*.

- *Diversification benefits from accessing a wider range of energy supply options.* Power imported through an interconnection can diversify the forms of energy in the receiving system and may reduce energy price risk.

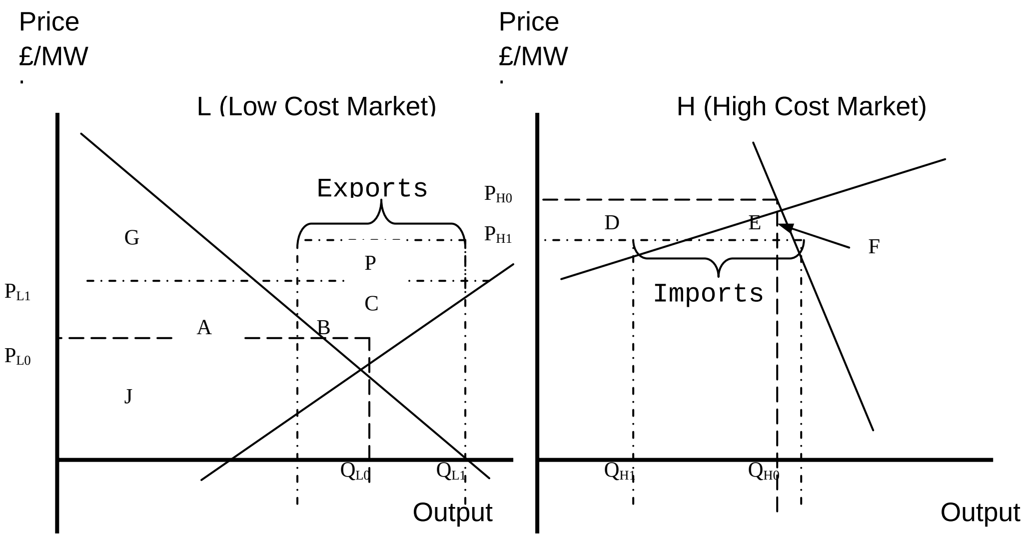
- *Economies of scale.* Larger generation projects that take advantage of economies of scale may only be feasible with access to a large markets provided by interconnectors. Similarly, generation units in small markets may be limited due to reliability considerations. For example, two 400MW units, with 400MW spinning reserve, for example, will be cheaper than a more efficient 800MW unit when the cost of 800MW in reserve is taken into account. This constraint is effectively removed with adequate interconnection.

- *Reducing market power in generation markets*. By allowing a greater number of generators to compete with each other, transmission can reduce market power in national or regional markets. One of the objectives of the Tasmania-Victoria interconnector, Basslink, for example was stated to be to introduce competition into electricity supply in Tasmania, enabling energy prices to be set by competition rather than regulation.

These social benefits may or may not be realised by private investors, who derive value from selling access to the interconnector, which it turn allows users to make arbitrage profits from buying services (mainly power, but perhaps also balancing and ancillary services) in the cheaper market and selling into the dearer market. If the market price of these services reflects their social costs and value, then private values will derive from the same sources of value above (except, of course, from the benefits of reducing market failures such as market power).

It is important to note that while such benefits may result in net gains for the system (or interconnected systems) as a whole, there may be distributional impacts - winners and losers - on the various participants within the system. In figure 1, we examine the changes in consumer and producer surplus from the interconnection of two markets assuming that both markets are competitive.[4] One market has relatively low cost electricity (L) and the other high cost (H). As separate markets without cross-border trading the initial electricity prices are P_{L0} and P_{H0}, found by the simple intersection of the supply and demand curves. The consumer surplus in region L is area G+A+B and producer surplus is area J. If we now assume the construction of an interconnector with limited capacity, this allows the import of electricity from market L to market H. The price of electricity is region L rises from P_{L0} to P_{L1} and the output from Q_{L0} to Q_{L1}. Accordingly, producer surplus in the low cost region rises by areas A+B+C. Consumer surplus falls by areas A+B. In the importing system, the price and output falls (P_{H0} to P_{H1} and Q_{H0} to Q_{H1}). Producer surplus falls by area D and consumer surplus increases by areas D+E+F. Hence, due to the variable costs savings from being able to transfer some of the generation to the lower cost region, there is a net gain of area C in market L (producer surplus gain A+B+C minus consumer surplus fall A+B) and areas E+F in market H (consumer surplus gain of D+E+F minus producer surplus fall D) with some redistribution from consumers to producers in the former and from producers to consumers in the later. These gains are in addition to the value to the owners of the rights to the transmission line, shown in the figure as area P. This is equal to the difference between the prices in the two regions multiplied by the export volume through the line. In the extreme case of the interconnector being large enough to eliminate any price difference between the two regions then there would be zero value for these transmission rights to the interconnector, while net gains for consumers and producers as a whole would remain (and would be maximised, although at the cost of extra capacity – which would likely not be justified).

Figure 1 Gains from interconnection



2.2 Costs

The costs of a transmission project include:

- Construction costs and system integration
- Ongoing maintenance costs
- Environmental impacts

Compared to the uncertainties over the size of the benefits, the cost uncertainties are relatively minor. They are the same as most other types of large engineering projects, except perhaps for uncertainties about obtaining the necessary planning permissions for possible routes (Turvey, 2005).

[4] Consumer surplus is the economic gain accruing to a consumer from engaging in trade. It is the difference between the price they are willing to pay and the actual price. The aggregate consumers' surplus is the sum of the consumer's surplus for each individual consumer and can be represented on a supply and demand figure. It is the triangle formed by the intersection of the the demand curve with the horizontal line representing the price (and bounded on the left side by the price axis).

2.3 Interconnector Studies

In this section we briefly review the typical procedures employed for evaluating interconnectors between regions.[5]

The three steps of an interconnection appraisal consist of:

1. Creating a set of plausible alternative projects to the interconnection;
2. Preparing a range of possible market development scenarios; and,
3. Conducting an economic analysis of the interconnection project, along with the alternative pro jects, under each of the market development scenarios (Turvey, 2005).

The first step identifies the necessity of establishing one or more counter-factuals to the proposed project. There are usually substitute possibilities for a transmission project, including the construction of new generation facilities. The identification of possible rival projects usually requires engineers to develop plausible alternatives. Often, possible alternative projects will have been put forward by those proposing the interconnector under consideration.

The second step, the development of market development scenarios, involves making a number of different assumptions about factors which may affect the value of a project. These include issues such as future demand growth, fuel prices, water (hydro) availability, outage rates, market design developments, and government environmental policy.

The final step involves evaluating the proposed and rival projects using simulations of the system under the market scenarios. In some cases the evaluations can involve attaching monetary values to the costs and benefits discussed in previous section. In other cases, it may require the system to achieve some index (such as reliability levels). Monte Carlo methods may be employed in these simulations or at least postulating a number of alternatives to the baseline scenarios in order to examine the sensitivity of the results to the various market factors. Historical data can sometimes be used to evaluate the use of the interconnector if it had existed in the past.

Another important assumption in the simulation is the manner in which the pricing behaviour of generators is modelled. This will not only directly determine the flows across the interconnector but also the amount and type of new entrants and the timing of the retirement of old plant, with longer-run consequences for the size of these flows (Turvey, 2005).

There are obviously substantial uncertainties underlying these simulation models. Looking forward over a series of years, from knowledge of the costs of new generating plants it may be possible to predict trend levels of prices at periods of high and low load. The expansion of renewables capacity and the nature and effects of future emissions controls already creates additional uncertainty. However, the actual volume of interconnector use will depend upon actual prices in the two systems, and, as historical data demonstrate, daily and even hourly fluctuations around the trend can be very considerable, depending upon a host of transitory factors.

The simplest cases arise when the proposed interconnector would link a system with good energy resources and low generation costs to a system with high generation costs. The interconnector would be used at full capacity, and the benefits of fuel savings and reduced reserve requirements in the exporting country could be directly calculated.

Analysis becomes more complicated and less certain, if flows across the interconnector vary during the day and/or seasonally. Strategic pricing behaviour of generation companies further complicate the analysis, as it is typically difficult to predict. Forecasting prices in one system is difficult enough; forecasts of price differences between them are even more uncertain. The proposed NorNed interconnector is an example of an interconnector whose value is primarily driven by differences in short term prices between two markets (although drought conditions in Norway may occasionally produce seasonal flows), which in turn derive from the different generation parks – hydro in Norway and thermal power in the Netherlands. The hour-by-hour price differences are caused by differences in variable

[5] For concrete examples of interconnector evaluation studies see Awad et al (2004), Consortium of Electric Reliability Technology Solutions (2004), Ilex Energy Consulting (2004), Tabors et. al. (2004), SKM Energy Consulting (2003), DKM Economic Consultants et. al. (2003),

costs, different patterns of electricity consumption and by random “price volatility” effects in the two countries. The different patterns of consumption arise from, for instance, the fact that in the Netherlands a larger proportion of electricity is used by light industry and commerce rather than baseload demand by heavy industry. Unplanned outages of generators can also induce price volatility that can lead to profitable trading (Turvey, 2005).

Further benefits could arise due to the opportunity to pool reserves. In the case of the proposed North Sea Interconnector between Norway and Britain, for example, usual flows during daytime are expected from the hydro resources in Norway to Britain. However, during dry years some of these flows might be reduced or backward flow from Britain to Norway during off-peak periods increased. Thus some investment in generation capacity in the joint system could be saved. In electricity markets without capacity payments the corresponding scarcities are reflected in price spikes – a further dimension that complicates the prediction of benefits. A similar economic motive drives the BassLink project in Australia between Tasmania (with hydro resources) and Victoria (with thermal resources).

Finally, the potentially largest value of interconnectors results from the pooling of operational reserves; even more so if one of the system can offer flexible hydro power. Storage hydro offers the valuable service of short-term buffering of fluctuations in supply and demand, and this value increases as the share of intermittent wind generation on the system increases. Once again, the value of pooling reserve hinges on the cost of operational reserves, which is a function of the available technologies, power stations, fuel costs and reserve requirements, and thus rather difficult to predict.

2.4 Regulatory Approval

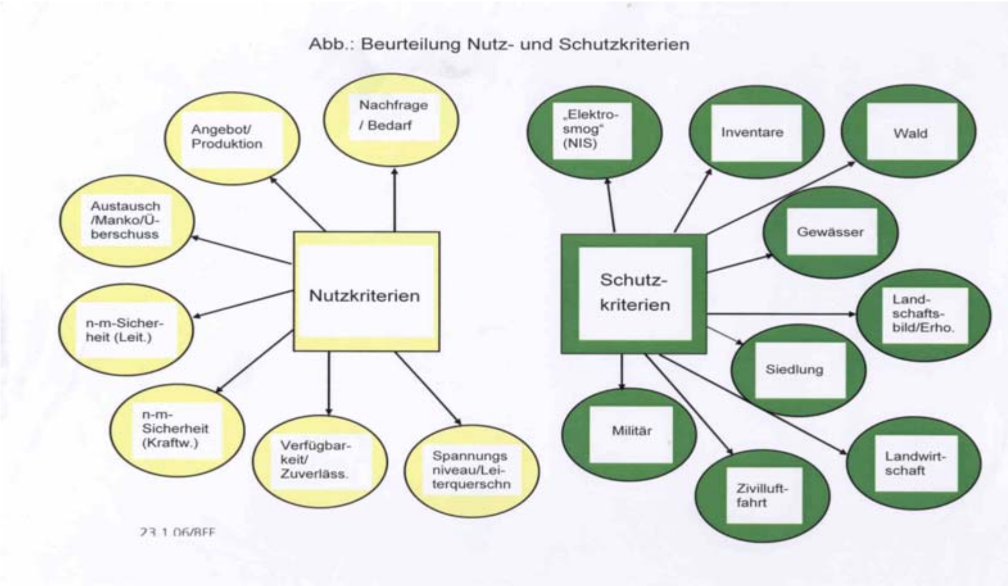
As will be discussed further below, an important transmission policy design question is whether and how the regulator should conduct a “regulatory test” on proposed transmission expansion projects. Such a test could be applied to only projects receiving regulated revenue or to all projects including those that are intending to be funded purely through trading (merchant). Conceptually, the rule should be able to distinguish between justified and unjustified investments, using techniques discussed in the previous section. In simplified terms the rule would be something such as: “One should invest in transmission network assets only while the additional network investment cost is less than the saving in system operation costs”. More complex rules may be needed for merchant investment, to ensure that they do not pre-empt planned regulated investments that would yield higher social value.

Obviously, and expressed in simplified terms, when alternative investment possibilities exist, the network planner should choose those maximizing the difference between operational savings and cost. Note that the regulatory test should allow the justification of so called “reliability lines”, i.e. lines whose justification is mostly because of a general improvement of reliability conditions in the power system. Reliability can, conceptually, be quantified in economic terms, even if the beneficiaries whose reliability conditions are improved might be widely dispersed. In other cases “reliability lines” may be dictated because of mandatory requirements in national or international grid codes. Joskow (2005) notes that in practice it may be difficult to distinguish between reliability lines and economic trading lines, as economic lines usually contribute to reliability.

While the regulatory test may be easy to state in terms of costs and benefits and is conceptually sound, the regulatory test is very difficult to apply in practice in strict terms. Different kinds of approximations and simplifications, of the types discussed in the previous section, are used in practice throughout the world by regulators. As we will discuss further below, this is a reason given for advocating merchant transmission investment which relies on the (presumably) superior decision making process of a competitive market. However, as we will see, there is another set of problems associated with merchant transmission investment.

Box 1 SFOE Transmission Investment Approval Criteria

The SFOE currently use a number of criteria for approval a new transmission. However, economic welfare considerations are only cursorily examined.



In Australia, investors have the option to be unregulated and rely solely on the price differentials between the two nodes, or rely on regulated revenues, which partly consist of regulated connection charges. In order to qualify for regulated revenues the investment has to pass the regulatory test. The test is passed if the investment has the highest net present value of market benefit compared with possible alternatives. The range of possible alternatives might include an interconnector with a different size, or following a different route, or re-inforcement of the domestic grid (which may alleviate constraints on other interconnectors and improve price arbitrage) or local generation investments that alleviate local shortages and high prices. The main advantage of an explicit test is that obvious detrimental investments can be checked. The main disadvantage is that it inevitably introduces an arbitrary and bureaucratic element in an otherwise market-driven environment. Littlechild (2004) is critical of a recent application of the regulatory test and subsequent approval of a regulated project in the so-called SNI case in Australia. In a recent review, the Australian Competition and Consumer Commission (ACCC) raised interesting questions concerning the regulatory test (ACCC, 2003). One question concerned the alternatives to be examined. First, were new power plants alternatives to new lines? Second, the test included modeled projects, "likely to be commissioned". This seems reasonable but opens up gaming possibilities: firms can "model" fake projects.

The ACCC also questioned the measurement of social costs and benefits. First, new lines will in general have an effect on the competitiveness of the generation market on both sides of the line. A large part of the impact will be transfers from generators to consumers or vice versa (depending on the direction of flows), and the change in deadweight loss arising from more intense competition is likely to be very small (as demand elasticities are so small). There is a feeling that only to count the direct deadweight loss reduction understates the competition effects that should be taken into account in the social cost-benefit analysis. For example, a more competitive market is likely to induce less "excess entry" and require less regulatory intervention (which, as California demonstrates, can be hugely costly)[6]. The question of how to measure the effect on and value of increased competitiveness re-

[6] With the potential exercise of market power it is difficult both for investors and for regulators to judge whether high prices are caused by scarcity or by withholding of output. One of the reactions of the California government to the crisis in 2000 was to sign long-term contracts for electricity supply at prices that are rather unfavourable for customers.

mains open. Second, new lines will have network effects. For instance, a new line can increase the reliability of the network, but might also require a network upgrade elsewhere. Thus there is somewhat more discretion in the definition of the project.

The jury is still out on whether a regulatory test is workable at all and if not, whether a tender for constructing and operating the (unregulated) line would be a feasible alternative.

Box 2 Transmission Evaluation Issues – Relevance for Switzerland

- **Sources of value**
  Switzerland represents an excellent case of a country with multiple sources of value from their electricity resource. Its storage hydro is of significant value to neighbours with either high capital cost base-load plant (French nuclear power, German lignite) or high peak prices (Italy), while its location allows high price Italy access to lower cost sources of power to the North and West.

- **Interconnection evaluation skills**
  The approval process for proposed transmission lines in Switzerland currently does not contain any detailed economic evaluation, but this will doubtless change if transmission is functionally unbundled from generation.

- **Regulatory tests**
  The regulator will share some responsibility with the TSOs to ensure that Swiss customers are provided with reliable, secure and economic power, and will therefore need the ability to ensure that transmission investments do not prejudice these goals.

3 Regulatory and Financial Reward Structures for Transmission Infrastructure

The results of a regulatory test or interconnector cost-benefit study can establish whether a transmission project is socially beneficial, or whether it is privately profitable but socially costly (in which case it should either be prohibited, or, preferably, the distorted price signals that drive a wedge between social and private costs and values should be corrected.[7] However, even if the interconnector appears socially beneficial, this does not mean that transmission will be built if the proper financial incentives are not in place that adequately remunerate the project. The aim of this section is to provide an overview of the two main regulatory frameworks and financial reward structures for transmission network expansion.

3.1 Regulated Transmission Investment

The traditional approach to transmission investment may be a described as a centralized process of "predict and provide" and rewarding the investments with regulated tariffs. The transmission system operator (TSO) forecasts demand for transmission capacity, or responds to requests made by the network users or regulators and, subject to an appropriate cost-benefit analysis, builds the line to meet demand. The returns to the investment are provided by a approved charge to be paid to the TSO by users of the network. This type of planning and remuneration derives, to some extent, from methods employed by pre-liberalized vertically integrated incumbents in the simultaneous optimization of transmission and generation.

Under this approach, while TSOs may usually initiate the proposal for the development of a new piece of infrastructure, the regulator has a key role to play. The regulator would most likely explicitly judge the merits and desirability of each investment based on a set of prescribed criteria as described in the previous sections, including security and economic efficiency.

The cost of a project is usually recouped through regulated tariffs charged to users of the whole system. The manner of estimating the cost of a new project to be added to the regulated asset bases can proceed to two ways (CEER, 2004):

- *Standardized Listed Prices.* The remuneration for a particular piece of infrastructure can be worked out according to recognised or certified standard costs (investment, operation and maintenance costs) with an adequate rate of return that makes the investment attractive.
  - The remuneration system would be divided into two parts: capital charges and operating costs.
  - The capital charges would be determined by the depreciation cost plus the cost of capital, as valued by the regulatory authority.
  - The cost of capital used could be delivered from one of the several widely used financial methodologies.

Tendering. The accredited or acknowledged costs of the project could be chosen through public tender. The tender can vary in the way in which it allocates construction and revenue risk. First, the lowest risk for the private investor, and simplest contract structure, requires bids that specify the construction cost. The company or consortium that offers to build the most cost effective line wins the tender. Second, a public private partnership typically also requires the company or consortium to maintain the line, and thus specifies the annual payments to the company. In the case of a transmission line one would envisage contract provisions that increase the payments if the line is operated at extremely high load factors as higher temperatures might increase the required maintenance frequency. The contract might also specify the allowed outage times, and could contain financial incentives to create high

[7] Loop flow effects can imply that some grid expansion reduce the transmission capacity of the network. While such projects might be profitable if the investor can collect the created congestion rents, or if the investor benefits from the created market power, such expansions are not socially desirable (Bushnell and Stoft, 1997)

availability. Third, the tender could ask bidders to specify a transmission charge. As a result the investors will receive higher revenues if the line utilization increases. Such exposure to volume risk seems desirable in circumstances where the investor has a strong influence on the utilization e.g. in the case of hotels where demand depends on service quality, or high quality transport links. In the meshed transmission network an investors has little influence on the utilization of any transmission line. For example, environmental regulation or renewable support schemes can induce significant changes in the generation pattern. Exposing private investors to uncertainty over which they have no control has no benefit in terms of increasing their performance incentive, but the increased risk increases financing costs.

The regulated transmission expansion approach has some immediate advantages:

- It represents a short step from most pre-liberalized market systems and so may be relatively easy to introduce in the short term.
- Monopoly rents may be regulated.
- The centralized and regulated nature of the process provides a relatively secure and controlled environment in which infrastructures can be built. In particular in designs where returns are guaranteed for investment that is part of the regulatory asset base, investors are less exposed to regulatory uncertainty and thus incur lower financing costs.
- Construction costs may be efficient since construction contracts can be tendered (CEER, 2004; Brunekreeft, 2004), the winner of the tender being the bidder requiring the minimum funding from regulated revenues. Of course, certain technical criteria would have to be applied in this case in order to guarantee quality standards. Competitive bidding processes to determine regulated rates help prevent the economic consequences of any errors in the investment cost estimation from being passed through to the network users.

There are, however, some problems.

3.1.1 Difficulties with the Regulated Transmission Investment

Apart from the well-known arguments for allowing market forces to operate where possible, regulated transmission has a number of well known disadvantages:

- In a world of competitive markets and unbundled players, the regulator lacks the information to forecast accurately, and must rely on the TSO, who is best placed to make the best forecasts, but may have incentives to misrepresent the demand for new transmission investment. This reduces the utility of any kind of ‘Regulatory Test’ that seeks to forecast welfare benefits of particular infrastructure proposals.
- If the regulated rate of return is mis-estimated and set too low the TSOs may be reluctant to propose new projects or upgrades, thus creating risks to security of supply. Conversely, if the regulator sets the allowed rate of return too high or the TSO forecasts greater than realized demand for capacity, there may be excessive (and uneconomic) investment and customers will pay too much. While it is easier to verify the requirement for a project than anticipating the need for a project, the information asymmetry between TSO and regulator cannot be ignored.
- These risks are amplified by the possibility of lobbying of Government, TSOs or regulators by special interest groups.
- Customers bear the risks of inappropriate or inefficient investment rather than the participants that proposed and built the line.

For transmission interconnection between regions a number of specific difficulties have also been identified:

- Vertically integrated utilities have poor incentives to invest in interconnector capacities because interconnectors may increase competition (and lower prices and profits) in their own generation markets.

- Regulatory uncertainty can impede investment by regulated private transmission companies. Gans & King (2003) quote a discussion of the Australian Productivity Commission on “regulation holidays” for risky new significant investment. The argument is that a regulator cannot credibly commit to “allow high profits” if *ex post* the state of the world turns out to be good, but may be less concerned if the company suffers losses.[8] Hence, given uncertainty, the *ex ante* expected rate of return will be lowered, depressing investment. In the discussion in Australia, a commitment to refrain from regulation for a predetermined number of years is seen as a possible way out, opening the option of merchant investment.
- There is an additional public-choice problem. If permission to build a line is required at both ends of an interconnector, the authorities would each need to be convinced that the extra charges to finance a regulated investment can be justified on cost-benefit criteria as benefiting their jurisdiction. This may not always be the case.[9] Merchant transmission investment mitigates this problem because it does not require such a cost-benefit test (although regulators may still deny interconnection if they believe it reduces social welfare in their own jurisdiction). The central problem is that the requirement of economic approval allows other goals to enter the discussion and can easily be abused.

3.1.2 Transmission Pricing

A key issue in any type of regulated transmission framework is the level and structure of the transmission tariffs. The choice of these tariffs will influence transmission investment decisions, and uncertainty about their future level (or about the methodology that will be used to set the tariffs) can undermine investment planning. It is a prime regulatory duty to clarify the principles of any methodology, and to resolve any uncertainty as quickly as possible, while recognising that it is a complex task to design a regulatory system that delivers cost-reflective tariffs and incentives for efficient pricing and operation. Difficulties arise because such tariffs not only serve the purpose of providing long-term financial compensation for capital investments but are also an important signal for short-term utilization of the network (including losses and congestion) and long-term siting signals for generation and load.

It is generally accepted that nodal pricing system is the optimal transmission pricing scheme.[10] The locationally differentiated energy prices implicitly incorporate the effect of losses and congestion in the grid. As well as sending efficient short-term operational signals, the resulting net surplus from the differences in nodal prices will, under ideal circumstances (with all attributes such as reliability correctly priced) recover total network costs. However, in practice the revenue is usually only able to cover approximately 20-30% of costs (Perez-Arriaga & Oreriz, 1995).

[8] A similar problem arises in the US where investment must be “prudent” and “used and useful” to qualify for receiving regulated revenues, but in that case it only earns the normal rate of return.

[9] Although if the line is economic, this would indicate a failure of cross-border tariffication and may be soluble by additional contracts.

[10] The main qualifications have to do with mitigating market power, and whether the additional measures needed to ensure that generators do not exercise market power to the extent that seriously distorts nodal prices outweigh the advantages of better locational signals. Even in strongly meshed systems losses will vary by node and time, and unless the grid is seriously overbuilt, one would expect constraints to emerge in some conditions, and these are best captured by nodal pricing. That said, the costs of nodal pricing may outweigh the benefits if the nodal prices have little impact on operation and investment decisions.

Congestion Management

Most European countries, including the Swiss, do not reflect transmission constraints within the country in their market design. Within the country trade can be performed and any transmission scheduled. The system operator uses bilateral contracts with specific generators (e.g. must run provisions), or bids submitted to the balancing market to readjust the generation pattern should the submitted flow patterns violate transmission or stability constraints. This approach creates four drawbacks relative to an efficient nodal pricing benchmark.:

- Generators are not exposed to the congestion signals, resulting in inefficient dispatch, demand and possibly investment patterns.
- The system operator needs to contract with generators in export constrained zones in order to reduce their output. Thus these generators (a) receive double revenue for being at an inappropriate location and (b) have the opportunity to exercise market power to their advantage during these negotiations.
- The system operator aims to minimise the need for redispatch within the system. Therefore he will limit the amount of new generation connected to the system in (potential) load pockets. This is likely to result in an inefficient under utilisation of the network, creating higher investment costs for network expansion or excessive restrictions for connection of new assets.
- The system operator prefers to allocate transmission capacity for internal use in order to minimise internal re-dispatch, thus limiting the ability to accomodate international transactions even if these would allow for a higher value use of the network.

Two types of market design do address these difficulties:

First, integrated transmission and energy markets are implemented in Scandinavia (called zonal pricing or market splitting) and in the North East of the USA (nodal pricing). Generation companies, large electricity customers, and supply companies submit bids and offers to a system operator, which specify the price, location and quantity they want to buy or sell at. The system operator determines a separate price for each zone or node at which accepted bids pay and offers must be paid for. If all bids are competitive, this implements the welfare maximising dispatch. Zonal pricing and market splitting simplify nodal pricing by aggregating several nodes into one zone at the cost of reduced efficiency and increased possibilities for the exercise of market power (Harvey and Hogan, 2000). Hogan (1992) supplemented nodal pricing with tradable congestion contracts (TCC), auctioned by the transmission operator to allow hedging and provide long-term information to guide investment decisions.

Second, separate transmission and energy markets are sometimes supported because it seems not to require centralised institutions and are currently implemented between most European countries with explicit auctions for transmission rights. Chao and Peck (1996) proved that the concept achieves a social optimum and therefore it coincides with nodal pricing complemented by TCCs in the presence of complete and competitive markets with no uncertainty and complete information. In reality not all these conditions are satisfied and recent academic discussions have identified the following advantages of integrated energy and transmission markets: Integrated markets save the transaction costs of trading physical transmission contracts, in potentially illiquid markets, for each half hour and each location to match all energy transmissions. Bushnell (1999) showed that generators can exercise market power by withholding physical transmission contracts; however 'use-it-or-lose-it' provisions are now frequently implemented and can prevent withholding, at least partially as Joskow and Tirole (2000) argue. Smeers and Jing-Yuan (1997) show that if only a limited number of traders arbitrage prices between the nodes, then they exercise market power and distort the dispatch. Harvey, Hogan and Pope (1996) argue that competitive generators and traders face uncertainty about the prices in the energy market when deciding on their bids for transmission markets, and might therefore buy an inappropriate amount of transmission rights. For congestion management within countries the liquidity of transmission contracts might be rather low, and thus create an obstacle for the implementation of separate transmission and energy markets.

Accordingly, additional (or alternative) sources of remuneration are needed to cover any shortfall in network costs. These will also be the sole sources in non-nodal pricing systems. Economic principles dictate that such costs should be assigned in a manner that minimizes the distortion to short-term pricing signals (and hence loaded more heavily onto components, such as the load connection charges, whose demand is least price-sensitive). They should be long-term price signals and, preferably, provide locational signals to new generation and load.[11] Ideally such charges should first reflect the deep connection costs that are not recovered through the use-of-system or nodal prices, and then, to the extent that there is still under-recovery, should be proportional to the benefits that the transmission network provides to the user, however this is difficult in practice as it is difficult to solicit non-marginal private evaluations.

One attractive choice is a two-part system. While some fraction of the transmission costs is charged proportionally to connected capacity or peak demand the remaining costs are allocated proportional to injected or consumed energy. In the UK, for example, generators and consumers pay annual fixed charges that depend on their location (by zones, of which there are 12-15) and their peak demand or capacity. Transmission losses are at present socialised.[12] There are ongoing efforts to make the energy related tariffs locational specific. This would expose operational decisions to the non-trivial differences in losses between different regions. In the UK the TSO has to not only ensure energy balance but resolve transmission constraints by accepting offers to generate where there is inadequate supply and bids to reduce output where there is an export constraint. Again these constraint costs are currently socialised (although incentive regulation has reduced them from over £400 million in the early 1990s to about £30 million p.a. currently, so this no longer attracts quite the attention it once did). The weakness of this method of congestion management is that firm access rights reward, rather than penalise, generators in export constrained zones and can encourage faulty location decisions. Some of these problems can be overcome with long term contracting (particularly in import-constrained zones) which can work quite well for conventional generation technologies. However, long-term contracts and the concept of providing enough capacity for firm access rights creates additional costs for intermittent generation technologies and limits the efficient utilisation of the network as they become more important.

3.1.3 Inter-TSO Compensation

Without an integrated international electricity pricing system, additional complications arise when electricity is transported between countries. Consider countries (and thus networks) A, B and C. If A exports to country C and most of the flow goes through country B, then country B is a transit country. Although the trade (from A to C) relies on network B, if each country's network costs are only charged to the generator and final user, A and C would not pay for the network in B. Horizontal inter-network compensation arrangements aim to repair this flaw and are discussed, in the European context, under the title cross-border tarification, CBT, or inter-TSO compensation. In the US CBT is also known as the "seams issue".

The compensation issue is irrelevant for efficiency as far as sunk costs are involved, although if the compensation is based on flow patterns, then it might induce network operators to distort power flows from the optimal dispatch.[13] Inter-network compensation becomes important whenever it affects investment decisions. In the European example the national regulator typically regulates the national network and there is no counterpart to FERC, which in the US has jurisdiction over inter-state (and thus inter-TSO) flows. The regulator in region B might not support a beneficial network expansion in country B if all the costs fall on generation and load in B and the consumers and generators benefiting in A and C make no contribution. Furthermore, the details of the compensation rule will affect grid revenues for A, B and C and thereby affect the use-of-system (UoS) charges required to make up the shortfalls in each area. These may then affect investment decisions for generators and load.

[11] Most load is not locationally mobile, but electric intensive industries such as aluminium certainly are.
[12] Several attempts by the regulator to move to the more efficient system of cost-reflective loss charging, as was the practice under the former nationalised CEGB, have been thwarted in the courts by Northern generators who would lose out.
[13] Thus TSOs may have an incentive to export congestion to neighbouring countries.

Whether this is empirically relevant depends on the amount of the compensation payments. As long as there remains large uncertainty about the future design of cross-border compensation payments, it will be difficult to justify interconnector investments, as these become sunk and less relevant to bargaining over the determination of the payments once made.

There have been a number of inter-TSO compensation schemes put forward. Two recent reports comparing inter-TSO compensation mechanisms (de Jong et. al. 2005; Frontier Economics, 2006) have demonstrated that there is no single mechanism which is preferable based on a number of evaluation criteria.

Vázquez, Olmos and Pérez-Arriaga (2002) discuss various schemes for charging network users for that (substantial) part of the total cost not recovered from congestion charges or charges for losses. The main methodologies are the marginal participation rule (or area of influence rule) and the average participation rule (or tracing).

The marginal participation rule or area of influence rule
The method of marginal participation attempts to estimate how flows respond to a change in injection (or withdrawal) of 1 MW at any node, with a view to charging agents at that node their share of the costs of the links on which flows change. Boucher & Smeers (2003, p. 20) stress the difficulty of the calculations and the arbitrariness of such cost-allocation rules and question the efficiency effects in general. Vázquez et. al. (2002) point out that the choice of the reference bus (slack bus) in the computational model effectively determines from which node the withdrawal (or injection) of 1 MW comes, and hence strongly influences the resulting flows. As a consequence the principle of the marginal unit can lead to unreasonable results if the marginal value in a line is significant although the “real” flow is negligible (Vázquez et. al., 2002).

However, it is important to note that irrespective of the choice of reference bus, if both generation and load are exposed to the same locational component, then the net total payment for a balanced transmission is not influenced by the choice of the reference bus. The choice of the reference bus only determines the allocation of costs between generation and load. Vázquez et. al. (2002) demonstrate this conjecture.

Conceptually, an increase in power in a competitive system would cause prices to change by different amounts at different nodes, and these price changes would stimulate changes in generation and consumption adding up to the required amount. The associated set of withdrawals would define the marginal changes in power flows and hence the relevant grid charges. This would almost certainly be an informationally challenging approach. Even if possible, it then remains to determine the fair amounts to charge for the use of these lines, and here we come back to the original problem that marginal pricing of lines leads to under-recovery, while average charges remove the efficiency justification.

The obvious objections to the marginal approach are that it is too complicated, apparently arbitrary, and likely to either under-reward additional investment, or over-charge relative to the efficient solution. That suggests the need for a simpler, defensible rule that would be acceptable to the various TSOs who have to reach agreement.

The average participation rule or tracing
This rule allocates responsibility for the costs of actual flows on various lines from sources to sinks according to a simple allocation rule, in which inflows are distributed proportionally between the outflows (Vazquez et.al., 2002). The main attractions of tracing are that they do not require the choice of a slack node. The drawbacks of tracing are first that aggregation of users can lead to counterintuitive results: If generation and load or different nodes are aggregated, then they are exposed to different tariffs. This can happen if the rule is confined to the high tension grid only, and there is generation connected to the lower tension grids that the rule ignores. Second, the choice of the allocation rule is decisive but apparently arbitrary. Its main defence is that it represents the Shapley value of a game between the TSOs (Kattuman et.al., 2004), and as such has the attraction that it is a recognised bargaining solution to a cooperative game.

The marginal participation rule is applied in Argentina (cf. Woolf, 2003, pp. 262 ff.), where it works reasonably well because of the simple architecture of the network. The load centre is Buenos Aires, which is the slack node, and the power plants are built near far away gas fields. The lines are mainly radial lines from the generation centres to the load centre, and thus the allocation of cost is relatively straightforward.

3.1.4 Incentive Based Regulation

For traditional regulated transmission investment, the regulated tariff charges are set equal to estimated costs plus a reasonable rate of return ("cost of service" or "rate of return" regulation). Unfortunately, such a pricing structure provides a weak incentive to minimize costs and improve availability and quality. Any cost savings or efficiency improvements can be clawed back by the regulator in setting the tariff to remain at the (new) cost-plus level. In light of this, there has been interest in a variant of regulating transmission called incentive regulation or performance based regulation (PBR), which is designed as a means of prompting more market-like behaviour from participants.[14]

The simple idea underlying incentive regulation is that by decoupling allowed revenue from the costs of transmission, the provider has the ability to increase and maintain profits by implementing cost reductions, productivity improvements and service innovations. By having a claim on residual profits there is a strong incentive for improved performance. The trade-off of course is that consumers will not get the full benefits of the lower costs.

There are a range of mechanisms that have been used to implement incentive regulation. The most well known is the price cap. Here the regulator sets an initial price (or a vector of prices for multiple products). This price (or a weighted average of prices) is then adjusted from one year to the next for changes in inflation (RPI) and a target productivity change factor "X." To set the initial price, typically, some form of cost-based model is employed. The calculation of X should be related to the expected or target rate of productivity growth of the firm, which will depend on how far it is from the efficiency frontier and how fast that frontier itself will move. Given data quality issues and the complex set of factors that determine individual companies' behaviour, experience so far shows that regulators retain some discretion in determining the final X factors. To increase transparency and reduce uncertainty it is desirable to identify methods to reduce this discretionary element. Benchmarking companies against national or international competitors is one natural approach, whose applicability largely depends on data comparability and the extent to which different circumstances can be controlled for in the data.[15]

In addition, it is well known that as price caps encourage cost reduction, there is a danger that this will be at the expense of the quality of service (Banerjee 2003). Accordingly, price cap mechanisms are increasingly accompanied either by specific performance standards and the threat of regulatory penalties if they are not met or formal PBR mechanisms that set performance standards and specify penalties and rewards for the firm for falling above or below these performance norms (OFGEM 2004d, 2004f). But while performance measures can be developed and implemented, it is difficult to separate and identify the impacts on measured performance (and the implied welfare of participants) *attributable to the actions of the transmission provider.* The performance measures for transmission are sensitive to the vagaries inherent to power markets of which many are outside of the control of the system operator, including but not limited to unexpected actions of generators, random failure of system components, economic activity, and weather. Exposing the system operator to strong incentive schemes based on performance operators that are partially driven by events outside of the control of the system operator might therefore, especially in small systems, increase the financial risk facing the system operator that in turn might increase financing costs. The typical trade-off between increased performance incentives and reduced capital costs applies.

To reduce the risk exposure of the TSO, incentive based mechanisms also often have a profit sharing provision or a sliding scale regulatory mechanism where the price that the regulated firm can charge is partially responsive to changes in realized costs and partially fixed ex ante. This has been particularly effective in Britain, where incentives to reduce constraint costs have lowered these costs from over £400 million per year to less than £30 million. More generally, it is also possible to offer a menu of cost-contingent regulatory contracts with different cost sharing provisions. The basic idea behind a menu is to make it profitable for a firm with high cost-reduction potential to choose a more high pow-

[14] For a more detailed discussion of incentive regulation in electricity distribution and transmission see Joskow (2005c). For a more general theoretical treatment of incentive regulation see Laffont and Tirole (1993) and Armstrong and Sippington (2004)
[15] See Farsi & Filippi (2005) for a benchmarking analysis of Swiss distribution utilities.

ered incentive scheme (with price caps set at a relatively low level) and those with low cost reduction potential to choose low powered incentive scheme (rate of return type regulation). This approach has also been tried in Britain for distribution companies.

Joskow (2005c) notes that even apparently simple mechanisms like price caps (e.g. RPI – X regulation) are fairly complicated to implement in practice and depart in potentially important ways from the assumptions upon which related theoretical analyses have been based.[16] Moreover, the robust implementation of an incentive based scheme still requires having sound accounting, performance and other technical data sources. For example, in the UK, the lack of a uniform system of accounts limited the effectiveness of the incentive scheme for electricity distribution and led to gaming by participants (e.g. capitalizing operating costs to take advantage of asymmetries in the treatment of operating and capital costs). Over time these accounting and reporting standards can be refined and clarified, but not without regulatory vigilance and effort.

There are also important dynamic questions in the design of a performance-based mechanism. In particular, how and when should the regulator review the price setting formula? As the review period gets longer the power of the incentive mechanism increases but so may an unacceptable level of rent extraction. A good regulatory regime needs to establish a handle on this tradeoff (Schmalensee, 1989). If a regulator can change its pricing policy in light of new cost information then this will have an effect, *ex ante*, on the regulated firm's behavior. For example, in the UK it has been observed that regulated firms appear to make their greatest cost reduction efforts during the early years of the price cap period and then exert less effort at reducing costs as the date of the price review proceeding approached (OFGEM 2004a, 2004b).

It can be better for the regulator to commit to a particular contract *ex ante*, which may be contingent on realized costs, but the regulator is then not permitted to use the information gained from observing realized costs to change the terms and conditions of the regulatory contract offered to the firm (Joskow, 2005). However, with changing technologies, demand patterns, and cost structures it seems inevitable to periodically review incentive schemes. Without such reviews the inherent uncertainty can result in financial risk for companies accumulating increasing losses or political risk for governments allowing for increasing profits. But with reviews it is difficult to envisage how the regulator will not incorporate new information in his decision process. Ofgem is experimenting with structures where the regulator promises to companies that they can retain efficiency savings for a period of five years after the savings have been realised, even if these five years are interrupted by a regulatory review. As regulatory methodology becomes more established in a country, such promises are increasingly verifiable and credible.

While incentive based regulation has been applied to electricity distribution utilities around the world (as well as water, gas and telecommunications), for three reasons it has been applied more rarely to transmission companies. First, in many continental European countries transmission companies are vertically integrated with generation. The separate regulation of individual value segments is challenging, given the difficulty of attributing common costs to segments, the restricted amount of internal information available to the regulator, and the possibility to use transfer rather than real prices. Second, in North America, transmission ownership is frequently separated from transmission operation (allocated to an Independent System Operator), as the owners often have generation interest that can distort efficient system operation. Without a solid asset base the transmission operator cannot be exposed to strong financial incentives, as it is unlikely to go bankrupt in the case of underperformance. Third, many of the benefits of incentive based regulation for transmission companies stem from the better coordination of operation and maintenance requirements. If this coordination is performed between two separate entities then strong financial incentives are likely to create large transaction costs to allocate responsibility for any individual transaction between these two entities.

The UK is represents a rare example where the transmission operator is exposed to strong incentive schemes. This is viable, because the operator also owns and controls the assets and is independent from generation interests. The UK for a long time had created the advantageous situation of a vertically unbundled entity that was both owning and operating the transmission network, allowing powerful incentives to be imposed on National Grid. Given the well-defined access rights to the interconnec-

[16] Thus for example, theory supposes that costs can be readily measured and compared, whereas developing a consistent set of rules for drawing up regulatory accounts is a challenging (but essential) task for the regulator. Similarly, determining the weighted average cost of capital and the regulatory asset value are often contentious, as is determining the efficient cost of new investments that should be added to the asset value.

tions between England and neighboring systems in Scotland and France, these incentives did not adversely effect trade flows with these neighboring networks, and the consensus is that National Grid's performance and the system of regulation has been remarkably successful. The operational responsibility of National Grid was extended to Scotland in 2005, and this should provide interesting insights as Scotland has until 2005 been vertically integrated in generation and transmission. National Grid is now in effect an asset-based ISO north of the Scottish border.

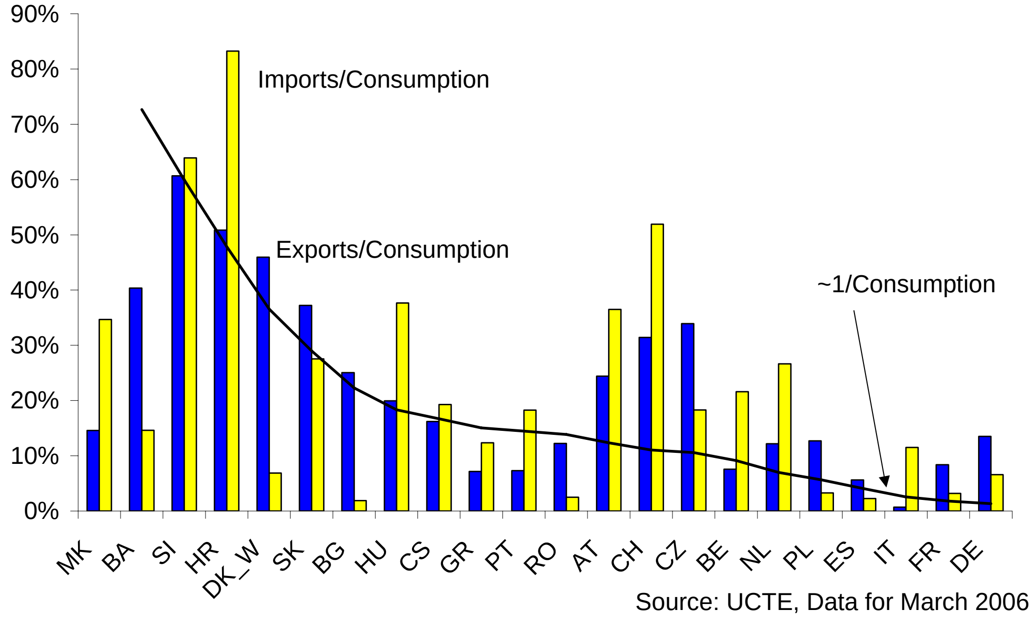


Figure 1a Volume of imports and exports relative to national consumption for European countries (March 2006). The countries are sorted relative to their inverse consumption (solid line)

This pattern obviously changes during the year, as the following graph illustrates at the Swiss example, with less hydro availability reducing exports during the winter.

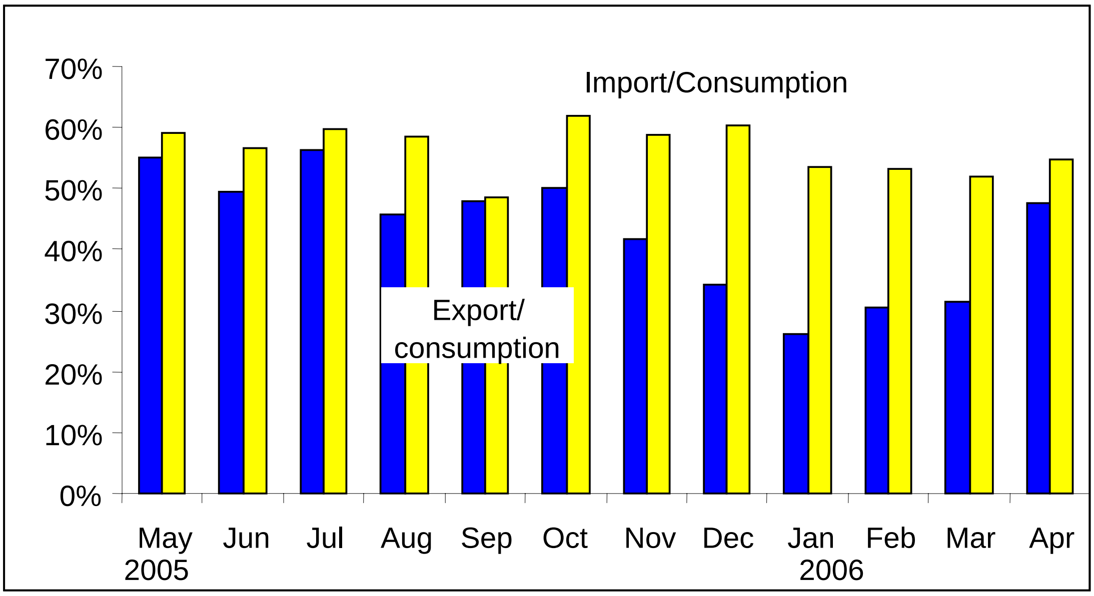


Figure 1b Evolution of exports and imports during the year.

How does this international experience relate to the Swiss context? Figure 1 illustrates the high volumes of imports and exports relative to domestic consumption. If the future System Operator, Swissgrid, were to be exposed to an incentive scheme like in the UK, where he bears the costs for resolving internal congestion, then the cheapest approach to do so would be to curtail the transmission capacity available for international transactions, likely to the disadvantage not only to international parties, but also to domestic generators and traders.

Furthermore, in contrast to the UK, Etrans does not own significant assets, and therefore would go bankrupt during the times of a bad performance under a powerful incentive scheme. This is a rather unrealistic threat, given the need for continued system operation, suggesting that de facto the regulator would not expose Etrans to the downside part of an incentive scheme.

In the absence of a powerful incentive scheme it is less appropriate to leave large amounts of discretion for operational decisions to the system operator, The positive experience of the systems in place in New England ISO, PJM and New York ISO suggests that this is viable if an effective congestion management scheme is in place (nodal pricing).

Box 3 Regulated Transmission Issues – Relevance for Switzerland

Switzerland will have to design a system of transmission regulation and its design will have important implications for system operation, generator behaviour (which will be influenced by incentives provided to the system operator or SO), and systems expansion. The merits of MTI will depend on the efficiency of regulated transmission and this efficiency will be affected by the choice of regulatory regime. The evidence from Britain and other countries is that these efficiency gains from effective regulation can be large but may take considerable regulatory development before they can be realised (and transferred to consumers).

One of the key issues for congestion management will be whether to adopt market splitting or nodal pricing, and whether to pursue market integration with neighbouring TSOs, as in the Nordic countries. Market splitting creates separate price zones when grid connections between them become congested, and these price differences will have an impact on the economics of any MTI (as well as on the prices and transmission charges that consumers and generators face). Market splitting and nodal pricing both offer increased efficiency of interconnector use and ought therefore to reduce congestion, as well as giving more reliable price signals for investment.

The experience of the Netherlands in particular in its dealing with Germany suggests that close collaboration between regulators is desirable but may be difficult (in Germany because there was until recently no regulator). That experience also demonstrates the difficulty of dealing with cross-border issues when transmission is owned by generating companies.

3.2 Merchant Transmission Investment

In this approach, it is left to the market to identify where to build new transmission lines and remuneration is provided by arbitrage between differently priced regions. The investment is not eligible to receive any of the regulated revenue (and might have to pay for connection to the regulated system, possibly net of estimated benefits provided to the rest of the system). The initiative to build new infrastructure may come from a coalition of electricity users (producers and/or consumers), an independent third party, or more problematically, a transmission system operator. Merchant infrastructure is thus developed and operated on a commercial basis outside the default regulatory regime applicable for national networks. A growing literature addresses issues raised by MTI (Brunkereeft, 2004, 2005; Joskow and Tirole, 2003; Hogan, 1999, 2003).

A range of business models currently exists for the operation of merchant infrastructure. On the one hand, the company which develops the line can also be its user and obtain revenue through buying and selling electricity on either side of the line. Another model involves the merchant owner/operator not using any of the capacity for its own trading but instead relying on revenues from the sale of capacity on the line to third parties. This sale can be on a long-term forward basis (often before the line is built as a way of financing the line) or as short-term capacity auctions, or some combination.

As we will discuss further below, Switzerland is in many ways the best-placed country to experiment with MTI for interconnectors, as these are to a considerable extent designed to benefit neighbouring countries and should therefore not place any burden on Switzerland. One of the problems they potentially sidestep is that they avoid the difficulties in calculating the appropriate level of inter-TSO compensation. Typically, transmission investment benefits national load and/or generation. The regulator, if acting in the national interest, should take these benefits into account in deciding on investments, and may reserve the right to provide regulated solutions where merchant investments fail to capture the potential national benefits. In the context of transmission lines which are carrying large fractions of transit flows, and are thus arguably not receiving an appropriate level of financial compensation under the current European inter-TSO scheme, the regulator might be less inclined to support a regulated project. It would not be in the national interest to allocate the costs to national ratepayers, if the beneficiaries are external. Even where the traders who operate or own the line are Swiss nationals, their profits do not feed back into reducing transmission costs to other network users, as might be the case with a properly designed regulatory option.[17] While we have not performed a quantitative analysis of projects to see whether this would be true in the Swiss context, it seems more likely to be the case than in almost any other EU country.

Merchant transmission investments already exist in various countries. The following list of unregulated MTI projects that are operating or in a planning stage is not complete, but does indicate that overall the number of such projects is rather limited compared to global investment in transmission capacity.

Australia:

- Directlink - 180 MW, 55 km underground DC line connection Queensland and NSW (converted to regulated link in 2005).
- Murraylink - 200 MW, 180 km underground DC line connecting South Australia and New South Wales (converted to regulated link in 2003).

USA:

- Cross Sound Cable – 330 MW, 38 km DC underwater cable connecting New Haven, Conneticut and Long Island, New York (currently operating).
- Neptune - 600MW, underwater DC line between New Jersey and New York (funded and to commence operations in 2007).
- Lake Erie Link - a 975 MW DC cable system under Lake Erie connecting the Ontario and both PJM and/or MISO (planning stage).
- Harbor Cable - an underground and submarine DC cable connecting PJM and NYISO (planning stage).
- Chesapeake Transmission – a 400 MW 230kV AC line connecting Chalk Point and Vienna, MD in PJM NYISO (having difficulties in attracting adequate bids in capacity auctions).
- Conjunction - 1000MW, overland DC line from upstate to NYC in NYISO (having difficulties in attracting adequate bids in capacity auctions).
- Trans Bay – a 55 mile 400 MW DC line from Pittsburg, CA to San Francisco (planning).
- Sea Breeze – a 22-mile 540 MW DC line between Washington State and Vancouver, British Columbia (FERC approved. Funding still required)

[17] Under the current EU rules for market-based allocation methods for managing interconnectors, half the revenue from the auctions should be returned to the network users or invested in additional transmission capacity.

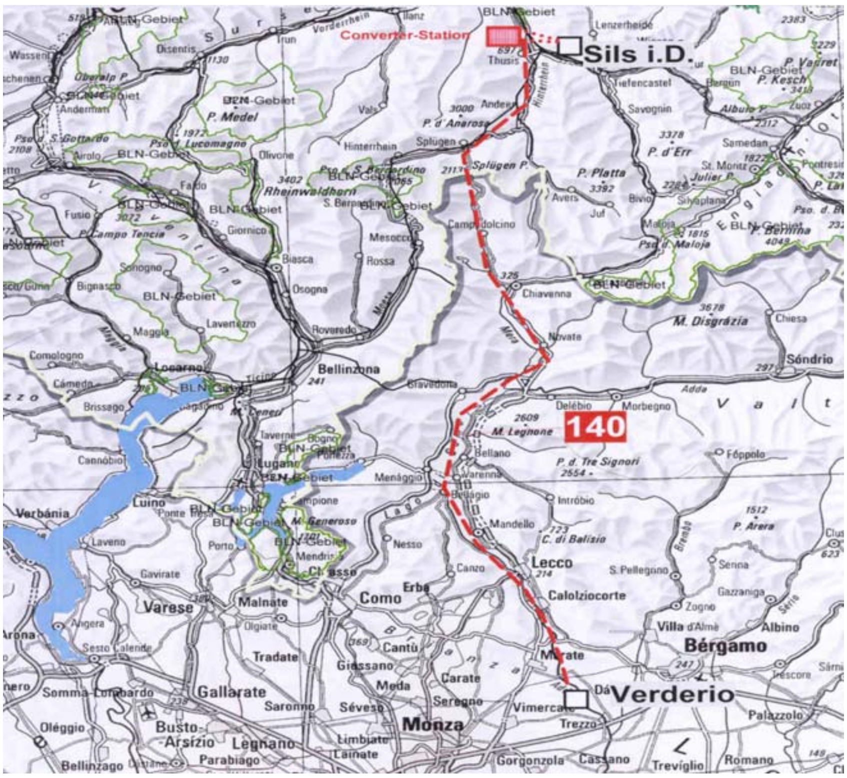
- Montana Alberta Tie – a 300km, 300 MW 230kV AC line AIES at Lethbridge, Alberta to NorthWestern Energy at Great Falls, Montana (permitting in progress).

Europe:

- Estlink interconnector - a submarine 350 MW DC link between Estonia and Finland. The partners in the Estlink project (through the company AS Nordic Energy Link) are the three Baltic power utilities - Eesti Energia, Latvenergo, Lietuvos Energija as well as Pohjolan Voima and Helsinkin Energia of Finland. The €110 million investment is 20% equity financed and bank loans guaranteed pro rata by owners. This is the first EC approved merchant interconnector. The plan is to convert the interconnector to regulated status sometime between 2009 and 2012 when it will be transferred to the direct ownership of the Finnish and Estonian TSOs.
- BritNed - a 250 km 1300 MW subsea DC cable connecting the UK and the Netherlands, aiming at trading between APX in Amsterdam and UKPX in London. A legally separated joint subsidiary of the TSOs on both sides: NGC in England and Wales and TenneT in the Netherlands. (Still in planning stage).
- Green Connector – Switzerland-Italy (see box 5).

It is important to note that both of the Australia merchant projects took up an option to revert to regulated status. Also only two of the US planned projects (Cross Sound Cable and Neptune) have so far succeeded in securing long-term funding.

Box 5 Proposed investment project GreenConnector:
Switzerland-Italy Merchant Project (Sils-Verderio).
152km, 400kV, 1100MW, DC



3.2.1 Transmission Rights

The two key elements of the merchant approach are locational wholesale prices (e.g. nodal, zonal) and well-defined transmission property rights. The rights are issued by the TSO, or in the case of cross-border links, jointly by the TSOs involved. In market designs with physical transmission rights the owner of the right is entitled to schedule transmissions up to the value of the right. In the case of integrated market designs (nodal, zonal pricing) the owner of the transmission right receives the price difference between regional prices from the institution that clears the energy market. This institution can cover these expenses as it makes a surplus when transmission constraints are binding and more energy is sold in high prices and bought in low price areas.

The basic logic of the approach is as follows:

- If some type of transmission right is granted to investors who expand the transmission system or build an interconnector, then investors will have incentives to build if these rights are (suffi ciently) valuable.
- The rights can be valuable because they will give the owner the right to move power from one end of the line they paid for to the other.[18]
- The rights will be valuable when transmission is scarce (i.e. when there is congestion) and so investors will have incentives to build when and where transmission is needed. The incentive will match the need because the alternative to building new transmission will be to pay the cost of congestion (Hunt 2003).

Many factors complicate transmission rights, and most can be solved in theory (Hogan, 2003). The original approach to merchant transmission financing involved the creation of physical transmission rights. The investor in the transmission capacity received the right to schedule physical flows proportional to the volume of the transmission capacity between the two endpoints of the transmission project. The main problem is that in an AC electricity network, power flows obey Kirchhof's laws and can only be directed either with DC lines or expensive power electronic additions.

In reality a grid expansion can therefore increase or decrease the ability of the transmission network to deliver energy from the sources to destinations. In regulated transmission networks this effect is considered at the stage of project evaluation, and only beneficial projects are advanced. With merchant transmission investment an individual investor could benefit from the ability to schedule flows along a line, even if the line decreases the overall capabilities of the system.[19] The US debate about merchant transmission projects in complex networks has recognised this problem and moved towards a solution. The merchant transmission investor receives transmission rights corresponding to the incremental capacity of the *whole network* that can be attributed to the merchant transmission investment.

This incremental capacity is in general different from the physical capacity of the grid expansion.

- In a well designed system the incremental capacity provided by a new line is typically below the physical capacity.
- In a system that was designed for a different set of load patterns, small physical capacity ex pansions can result in large increments of the network capability. This was illustrated by the dramatic success of the incentive scheme for National Grid. Small investments allowed NG to significantly reduce the constraint costs in the system, as noted above.

[18] Setting the remaining nodal or zonal prices and access charges correctly is crucial if these rights are to be properly valued, for otherwise there may be a temptation to interconnect two closely neighbouring nodes on either side of a zonal boundary between which there is a significant price difference. If the new link merely shifts the congestion a short distance from the ends of the new interconnector, then the nodal prices at each end of the link should move sharply together, correctly signalling that the interconnector of such a short length is not the efficient solution to the congestion problem.

[19] The general proposition that adding a link can degrade a network is known as Braess paradox, and a list of citations can be found at http://citeseer.ist.psu.edu/bean95braes.html. A specific example for electricity networks is provided, inter alia, in Blumsack (2006) 'Network Topologies and Transmission Investment Under Electric-Industry Restructuring', at http://wpweb2.tepper.cmu.edu/ceic/phd.htm. Bushnell and Stoft (1997) show how to avoid sch inefficient investments.

Arguably transmission operators might delay regulated investments, if they anticipate that they can implement these investments in the future as profitable merchant investments. This can be avoided with clear commitments of governments that exclude transmission operators from performing any merchant investment in their own or adjacent network.

Allocation of the incremental value of merchant transmission projects in complex networks can follow two approaches depending on the existing transmission pricing scheme. In the first, network studies calculate how much additional capacity a new transmission project makes available for a critical connection, e.g. between two countries. The result is likely to be that the new line increases the transmission capacity between two regions by a fraction of the physical rating of the line. This value can then be attributed to the investor, either in the form of physical transmission rights between the regions or in the form of financial transmission rights FTRs) between the regions if they are linked by market coupling/market splitting (e.g. Bushnell & Stoft, 1996). The market splitting approach simplifies the complexity of real world transmission networks by aggregating many nodes of the network into a virtual zone for the purpose of trading and usually even dispatch decisions. To allow for this aggregation without jeopardizing network security, higher security margins are required and thus less of the physically available capacity can be used for operation – both of old assets and of the new investment.

To address this issue the North East of the US has implemented nodal pricing, thus avoiding the artificial aggregation of nodes into zones that we currently perform in Europe. Transmission contracts are defined as financial hedging contracts. A merchant transmission line would then receive the incremental hedging contracts that are made available through the investment. Thus if an interconnector of 1000 MW to Italy allowed an additional import of 450 MW (because of security margins and constraints elsewhere in Italy and Switzerland, for example), then 450 MW of additional Italy-Switzerland Financial Transmission Rights (FTRs) could be issued. But to define the incremental transmission contracts, first there must be an auction to solicit the demand for existing transmission capacity. This is the challenging point for the approach as current demand for long-term hedging contracts is small. It is therefore unlikely that an auction for ten-year contracts will reveal the expected utilisation of the network. In the absence of this information it is then also difficult to determine the incremental value of the merchant transmission line.

Both approaches therefore run into the difficulty that the incremental capacity provided by an additional transmission line in a complex network is a function of the operation of the transmission system. In the absence of reliable predictions of network utilisation (the current European situation) or market demand for future hedging contracts (the US situation) it is thus difficult to define the value of a new transmission line.

The distinction between developments in the US on the one hand and Europe and Australia on the other hand is that nodal pricing approach in the US allows a more refined merchant system which represents the finer detail of the grid architecture and thus attributes higher value both to existing and new projects. Such schemes, unfortunately, create considerable complexity in their implementation, because they require the allocation of residual rights created by the merchant investment. This requires several years of multi-round auctions to identify the demand for transmission rights in the absence of merchant investment. Moreover, incremental FTRs require centralized allocation of transmission rights and are against the spirit of decentralized market-driven decisions (Joskow & Tirole, 2003).

3.2.2 General Difficulties with the Merchant Approach

Aside from implementation issues relating to transmission rights, there are a number of more generic problems that undermine the performance of the merchant transmission investment model and provide reasons why merchant investment may be suboptimal. These include:

- *Economies of scale and cost-recovery*. Transmission projects typically involve large economies of scale – crudely put, if it is economic to build a line then it is usually optimal to build a relatively large line. However, the larger the line, the more likely that the price differential between the regions connecting the line will be reduced. Since merchant transmission financing relies exclusively on these price differentials, a large line may not entirely recover fixed costs with the optimal capacity size. If investors cannot expect to recover at least their investment costs effectively, they will not have incentive to invest in the optimal sized line (from a total welfare perspective) and will build a smaller line. The problem is exaggerated if there is a monopoly on linking the relevant regions. However, Brunekreeft (2004) points out that a tender with various competitive participants for building the line, where the winner is the bidder offering the largest capacity, should be close to the second-best capacity, where the remaining price differential is just sufficiently high to recover all costs.

- *Loop Flow Effects*. In a meshed AC network, as already discussed, a new line can be privately profitable but social detrimental due to loopflow effects (e.g. Bushnell & Stoft, 1996). Hogan (2003) has shown that a set of point-to-point incremental financial transmission rights can solve the problem but this requires an underlying system of nodal prices (and still has implementation issues, as discussed above). Since such a system does not operate in Europe, such a set of incremental FTRs cannot be employed. Brunekreeft (2004) has noted this point as an argument in favor of restricting MTI to DC interconnectors in Europe. Even with DC lines there are still network effects, but these are not dissimilar from those of building a new generator and a consumer at the other end of the line (which would typically not be prevented from entry for reasons of network effects, as these should be captured by the grid connection an duse-of-system charges – which might also be levied on MTI in such cases).

- *Provision of public goods and free-riding problem*. Even if a transmission line may reduce congestion to a low level and thus not finance itself through short term trading arbitrage, it may still provide benefits that can be financed through long term contracts from the benefiting parties on either side of the line. However, there then arises a free-riding problem in that many of the connected participants may benefit from the line regardless of whether they contribute to the construction or not. Roughly speaking, the more meshed the network is and the more public the benefits (e.g. reliability) the more difficult it is to identify and coordinate users in a coalition of financiers.

- *Crowding out*. Hogan (2003) notes the danger of the 'slippery slope'. In environments where both regulated and merchant based investments exist at the same time the mechanisms might interfere with each other. As discussed above, merchant investments tend to be of smaller scale to ensure the line retains scarcity value. After a merchant investment, a parallel investment financed on regulated base could reduce this scarcity value and thus the profitability of the private line. Commitments to avoid such investment are difficult to define in complex networks given the multiple functions of transmission lines. Anticipation of future regulated investment might thus undermine the investment incentive for unregulated investment and crowd it out, deterring or delaying investment.

- *Market power of transmission investors*. There are possibilities of exploiting market power via the transmission owner's right to withhold transmission capacity (see discussion below on access and must-offer provisions).

- *Market power of generation companies.* This arises in the European context because of transmission constraints – in their absence the Swiss and European wholesale market for electricity would be competitive. The access market design for allocation of scarce transmission resources and its interaction with wholesale trading for electricity can help to reduce the exercise of market power of generation companies. Thus a regulatory environment that supports merchant investment should not increase the distortions that could result from strategic behaviour of generation companies. This is more likely to be a problem when interconnectors are built and controlled by importing generators with local market power (Gilbert, Neuhoff and Newbery, 2004).

- *Institutional Lock-in*. Merchant investments may lock in the current institutional and regulatory environment (e.g. decentralized power exchanges) which make changes to future regulatory intervention difficult (even if such future regulatory changes would otherwise be welfare enhancing). This is a serious concern given the ongoing discussion about optimal pricing schemes and the expected changes of network and generation technology in response to CO_2 reduction objectives. If it is proposed to change the system of pricing (e.g. from a postage stamp with a distance independent transmission fees to be paid by the generator or respective trader to nodal pricing which relates transmission costs to the respective locations of generation and demand), then merchant investors might object and delay desirable changes. Perhaps the right of conversion to a regulated status as in Australia can relieve the problem, although not without some moral hazard.

3.2.3 Specific Regulatory Issues

In the light of these problems there a number of regulatory issues that have to be solved in the development of a policy framework for merchant transmission investment.

3.2.3.1 Ownership

The key ownership question is whether a regulated TSO on either side of the unregulated transmission line should be allowed to be an owner of the line. The unregulated revenues of the line depend on the flow on the line and the price differences between the connected markets. Whereas these should be determined by the markets, they can be influenced quite strongly by the TSO. It seems natural to expect that the TSO will have incentives to prefer dispatch choices that increase profits on the unregulated lines. As discussed above the TSO might also deliberately avoid investment in regulated assets in order to retain profitable opportunities for the unregulated business. Given information asymmetry some of these opportunities might not be apparent to third parties and therefore not exposed to competition. Thus it seems preferable to exclude system operators from any interest in merchant transmission investment in their own or adjacent regions. That would not necessarily preclude a TSO from bidding to build a line that would then be owned by or leased to the interconnector company, if the TSO had a comparative advantage in line construction (as is quite likely) but the TSO would not be allowed to control access to or use of the line.

It should be noted that the argument is modified under strict separation of the system operator (SO) and transmission owner (TO), in which case it seems natural to allow the TO to invest in unregulated merchant transmission investment. Part of the firm would be regulated while another part would not be, but since the TO does not control the dispatch, it is not obvious how this regulatory mix could be abused. This result however hinges on two assumptions. First, the allocation of common costs between the regulated and the merchant business can be satisfactorily monitored to avoid cross-subsidisation. Second, the calculation of the required rate of return for the regulated business is not seriously restrained by the joint business activities. The merchant activities are likely to increase the risk profile and thus the capital costs for the joint business and may require the revenues and debt of the regulated business to be ring-fenced from other commercial activities. The principle is that the rate of return granted for the regulated activities should not be effected by other commercial activities. If these two aspects are resolved satisfactorily then a TSO can be a merchant somewhere else.

Indeed, a general restriction on TSOs investing in merchant transmission projects would be problematic, because they are the natural candidates to invest. For the proposed unregulated BritNed case, it implies that both TenneT and NG could not be owners. If it is felt that the TSO should not be allowed to participate it seems good policy not to grant the exemption from regulation and instead include the line into the regulatory asset base. This situation mimics the normal regulated TSO situation.

Another ownership question concerns participation limits of dominant generators. At stake is the question whether there should be something like an ex-ante rule or to leave the issue to competition law. For instance, the safe-harbour provisions in Australia limit ownership control to 35% of the generation capacity on either side of the interconnector (Brunekreeft, 2005).

3.2.3.2 Third party access provisions

A second issue concerns the design of the access regime. Should the line owner be allowed to participate in using the line or should this be fully separated? Should the line owner be free to determine who will be entitled to use the line, or should a non-discriminatory open-access regime apply?

In principle, in the European context, the essential facility doctrine of competition law requires that network owners must give access in order to allow competition on the network, although it may reasonably disputed that the interconnector is not an essential facility as it (or its effects) can be replicated. However, as we will discuss below, it is frequently argued by project proponents that with this provision they will not be able to finance the project. Thus various LNG terminals and gas pipelines have applied for and been granted exemption from third party access under Article 7 of the EU regulation. The access issue has also been fiercely debated in Australia, but consistent with the light-handed approach, the Australian merchant investment access regime has been restricted to the obligation to submit a code of access undertaking. The details are for the investor to decide, but should of course comply with general competition law.

For unregulated MTI it can be claimed that a third party access regime is unnecessary. Given that line revenues are unregulated, it must be in the interest of the line owner to handle line-usage efficiently. In a different context, the point has been forcefully brought by Director and Levi (1956) and Posner (1976, 1979), while more recently the argument re-emerged in the debate on the parity principle in telecommunications (cf. e.g. Baumol and Sidak, 1994). To maximise line profits it is usually in the interest of the line owner to allow the most efficient users (traders) on the line; discriminating against efficient third parties is usually profit decreasing.

However, by restricting the power flows on an interconnector the investor might increase the price differential between exporting and importing countries. As a result the revenue defined as price difference times volume of energy transmitted might grow. Such withholding may not appear, in the first instance, to be in the public interest.

3.2.3.3 Must-Offer Provision

The discussion above suggested that the line owner might increase revenues and profits by withholding some of the capacity of the line and thus increasing the scarcity value of the line. Should the regulator put in place a must-offer provision that requires the line owner to offer all capacity? Brunekreeft and Newbery (2004) analysed the effect on welfare. With the must-offer provision the line is utilised efficiently, but with uncertainty or demand growth the must-offer provision induces investors to delay investment or to reduce the capacity of the line. In their analysis a must-offer provision on merchant investment can reduce welfare relative to a case without must-offer provision (in the case in which regulated investment was not an option) and it can be better not to require a must-offer provision in exchange for encouraging a larger investment.

3.2.3.4 Capacity Reservation

Another question concerns whether at least part of the capacity of a merchant line should be reserved for the short-run spot market instead of selling all capacity in long-term contracts. In order to share the risks, there would likely be an incentive on the part of merchant entrepreneurs to sell off long-term contracts, possibly even before making the investment. However, this could impede competition if at a later stage new firms would be excluded from using the line and existing contract holders were unwilling to sell them in the spot market (perhaps because of the market power advantages they provide).

If transmission contracts are defined financially then this is of no relevance, because short-term allocation of transmission capacity follows the market clearing protocol independent of the long-term hedging positions.

Hence the remaining section only refers to physical transmission contracts. The example of merchant generation investments suggests that investors might independently decide to only sell some of the capacity on long-term contracts. This is however more attractive for merchant power stations with several units than for merchant transmission investment, because the uncontracted power stations serve as a hedge in case some of the contracted power stations fail. Both the failure probability and modularity of transmission projects is lower, thus reducing the value of uncommitted fraction of transmission capacity.

A requirement by the regulator on retaining capacity for the spot market is thus likely to increase the investment risk for merchant transmission investment, resulting in smaller or later projects. These disadvantages have to be traded off against potentially increased spot market liquidity that might result from requiring all interconnector trade to go through the local power exchanges (as is the case in the Netherlands). However, if the problem is lack of spot market liquidity, there are almost certainly better ways of increasing that without such an imposition on a new interconnector.

3.2.3.5 Option to Convert to Regulated Revenues

The merchant transmission experience in Australia has highlighted another consideration for regulators – giving MTI the option to convert to regulated status. In Australia, the reasoning behind having such so-called "safe harbour" provisions was provided by National Electricity Code Administrator (NECA, 1998) working group:

> … It might be argued that as well as the usual commercial risks, the proponent of a non-regulated interconnector may face additional risks related to market design deficiencies that may only become apparent once the first interconnectors are operational.
>
> Providing a right to apply for regulated status may help ensure that investment is not inefficiently inhibited by such non-commercial market design risks. However it is important that the conversion option should not shield the proponent from normal commercial risks, e.g., the risk of having over-judged the future demand for the interconnection service.

The Australia Competition and Consumer Commission (ACCC, 2001) similarly noted, in approving the provisions, that:

> the Commission understands that the provision to allow market network services to apply for conversion to prescribed network services reflects the view that MNSPs may face risks from future NEM developments, such as changes to regional boundaries, which may result in market network services becoming non-code compliant.

Such provisions can also therefore help safeguard against "lock-in" where useful institutional redesigns are prevented due to the adverse impact they would have on existing private parties. It is the same idea behind stranded-cost bailouts.

In consenting to allowing a MTI to convert to regulated status, unlike a regulatory test discussed earlier, the situation here involves an already sunk investment. This raises a difficult question as to what benchmark the investment should be compared against in order to set the appropriate size of asset base on which to provide regulated return. Brunekreeft (2005) has suggested calculating the best alternative as it was at the time the investment was made. This may be the project itself or an alternative (to be tested as required by the regulatory test). The rule would be to compensate the minimum of the real project and the best alternative; in other words, the compensation rule would be to pay the asset base of the hypothetical best alternative but not more than the asset base of the real project. If the calculated best alternative has the lower asset base, the criterion gives the project the value of how it should have been. Alternatively, the asset of the best alternative can be higher than the asset base of the converted project. If the asset base of the best alternative would be the benchmark, an investor has a perverse incentive to invest in small and cheap capacity and then request conversion. Taking the minimum value of the two options avoids this. On the one hand this rule safeguards projects against changes beyond its control, but not against inefficient managerial decisions, and on the other hand the right to conversion would not set obvious perverse investment incentives.

In Australia, the conversion regulatory test was applied to Murraylink in a way which was probably not satisfactory (Littlechild, 2005; Brunekreeft, 2005). The project was not required to maximise net benefit with regard to a number of feasible alternatives. Instead, the alternatives were chosen such that they provide the ''exact same level of technical service'' as Murraylink provides (ACCC, 2003b, p. xiv). This made the analysis easier but missed out on possible other options. The least-cost alternative then served to determine the regulated asset base for Murraylink. A key assumption in this step was that the least-cost option was an overhead line, whereas Murraylink is an underground line, creating a cost difference of AUS$ 100m (on a total cost of Murraylink of AUS$ 240m). In other words, ACCC claimed that, given the ‘‘exact same level of technical service’’, the commercial enterprise Murraylink simply missed an opportunity of AUS$ 100m. Murraylink’s objection was not awarded (ACCC, 2003b, p. xvii).[20]

3.3 Identifying the Dividing Line Between Regulated and Merchants Line

In the light of this discussion, it is worthwhile to identify instances where the existence of merchant investments could make sense and be desirable. The following inventory of situations is not meant to be exhaustive or limited, and it depends to a large extent on the specific regulation of transmission for the particular country or TSO.[21]

One instance would arise when a transmission investment seemed clearly beneficial to the system but for which the magnitude of uncertainties over both costs and benefits may be too large for the regulator to make a decision to authorize an investment under the regulated framework, as this may place too large a risk on consumers. In such cases, it may be that the entrepreneur has a different perception of the factors determining the risk and be willing to invest in the project under a merchant regulatory framework. While this may seem unlikely because of the cost of capital, there are good examples in Argentina where innovative approaches to construction sufficiently reduced the capital cost that the higher rates of interest were not a deterrent. On occasion special circumstances may exist that impede or delay the construction of a cross-border transmission investment by the official institutions, whereas a merchant investment may be more effective in having the required reinforcement built on time. This may be particularly simple in the case of submarine interconnectors joining two countries or TSOs, leaving room for merchant investments (CEER, 2004).

Another cases arises, which applies to some European countries, when the remuneration of the transmission activity in a Member State is not strictly based on some kind of cost-of-service scheme, but on some other criterion that reflects some measure of global network performance. Under these regulatory conditions, the TSO may not find it profitable to make a network investment (although network users would be better off if this reinforcement is built) (CEER, 2004).

A third situation, which is more likely in power systems with poorly meshed networks and where distances between convenient sites for power plants and major load centers are very large, is the possibility of associating the development of a new generation plant with the construction of the transmission line needed to evacuate the resulting power. This situation is more common in gas markets, where merchant transmission development is much more frequent than in electricity. In the Internal Electricity Market this situation may perhaps arise in relation to interconnectors with non-EU countries and in a few other cases.

[20] Murraylink may have opted for undergrounding to speed up environmental approval, and the benefits of advancing the date of the link should presumably have been added to the value of the overground alternative.
[21] These cases draw mainly upon CEER (2004)

Box 6 Merchant Transmission Issues – Relevance for Switzerland

Many of the issues discussed in this section are of a generic or theoretical nature. Given the relative lack of international experience with merchant investment it is difficult to estimate the relative importance of an issue in the specific context of Switzerland. However, there are some particular points of relevance for Switzerland.

- If forthcoming inter-TSO compensation schemes are judged to be unsatisfactory for Switzerland, then MTI avoids Swiss consumers paying for German, French, Austrian or Italian benefits, provided a regulatory test ensures no detriment via unwanted power flows within Switzerland.
- MTI may uncover innovative forms of interconnection (via tunnels?) that might otherwise remain unexploited.
- In some circumstances, especially between regions served by vertically integrated utilities, it seems difficult to reach agreement to deliver apparently attractive completions to the existing very high voltage grid, and the impetus to clarify the regulatory environment for MTI may also improve regulation of (and subsequent justified investment in) the regulated grid.
- MTI arguably introduces some competition into a country that has resisted competition.

Hogan argues for the following sharp distinction: socially beneficial but commercially unprofitable projects (large when compared to the relevant market) qualify for the regulated option while everything else should be left to the market. Littlechild (2004) expresses the same concern following his analysis of a recent application of the regulatory test in Australia, where regulatory opportunism appears to have had highly perverse effects. This may be a problem with loosely controlled state-owned enterprises and federal (competing) jurisdictions. Whether this is a useful distinction depends in part on whether one thinks the regulators are pursuing other goals than economic efficiency, and whether the system of regulation itself is satisfactory (or can readily be improved). Such judgements are highly country-specific.

4 European Regulations and Practice

In this section we discuss the standard European legal framework for transmission operation and investment.[22] This includes the special exemptions that have been made available for merchant investors. We also briefly examine the current cross-border congestion management system used in Europe and discuss the prospects for integrated approaches. The inter-TSO compensation currently employed in Europe is described along with the possible alternatives schemes that may be used in the future.

4.1 European Transmission Regulation

The most important transmission-specific legislation within the European Union is contained in the Electricity Directives 96/92/EC and 2003/54/EC and the Electricity Regulation (EC) No. 1228/2003, together with the new draft Guideline for the Regulation 1228/2003.[23] In addition, for issues for which for there is no sector-specific legislation, the general EC law (the EC Treaty) still applies.

Electricity transmission networks are considered to be natural monopolies under the Electricity Directives. Member States or the owners of transmission networks are required to designate one or more official transmission system operators (TSO). It is the responsibility of the TSO to maintain the ability of the grid to meet reasonable demands for the transmission of electricity. Tasks including operating, maintaining and, where appropriate, expanding the transmission system, including interconnections between states.

In this review we will limit the discussion of European regulation of transmission to three aspects that are of particular relevance. These are (a) network access, (b) transmission pricing, and (c) new investments in transmission networks.

4.1.1 Access

A cornerstone principle of the EU legislation is that TSOs are obliged to provide regulated third party access (TPA) to eligible customers. Under the earlier Electricity Directive 96/92/EC, the access status of interconnectors was not clear (Knops et al 2001). However, with the new Directives and Regulation it is clear that access of a customer to the transmission network includes, in principle, also access to the interconnectors of that network with other networks. In those cases where there is congestion on the interconnector, Article 6 and the Annex of the Regulation give general principles for congestion management. These principles contain a preference for using market-based methods. However, there is no compulsion for any particular congestion management technique. Importantly, with regard to the management of available transfer capacity (ATC), a recent judgment from the European Court of Justice[24] has determined that non-discrimination rules laid down in both Directives means that priority access to interconnections granted from pre-liberalization arrangements are discriminatory and are no longer valid, although whether this ruling applies at the Swiss borders with EU countries is still under discussion.

[22] For further discussion on EU transmission policy and how it relates to merchant interconnectors see Knops and de Jong (2005) and Knops et al (2004), upon which this section partly draws.

[23] At http://ec.europa.eu/energy/electricity/legislation/doc/congestion_management /cm_guidelines_en_v1.pdf

[24] ECJ 7 June 2005, Case C-17/03 (VEMW *et al.* v. DTe)

4.1.2 Transmission Charges

EC regulations require that tariffs for the use of transmission network must reflect the costs of using the network.[25] Either the tariffs or underlying methodology for calculating the tariff must be published prior to their application in practice.

Additional transmission charges may be imposed under conditions of congestion but the resulting revenue is then treated under congestion management regulations. Article 6 of the Regulation specifies that any revenues resulting from the allocation of interconnection capacity cannot freely be used by the TSO(s), but can only be used for:

- guaranteeing the actual availability of the allocated capacity;
- network investments maintaining or increasing interconnection capacity; or
- as an income to be taken into account by regulatory authorities when approving the methodology for calculating network tariffs, and/or in assessing whether tariffs should be modified.

Looking at how congestion revenue has been spent, table 1 shows that many TSOs obtain congestion revenues and that these revenues are not fully invested on projects to increase interconnector capacity. The table shows that only about one quarter of the congestion revenues is used to build new interconnections or to reinforce existing grid elements. This result from the Sector Inquiry demonstrates that incentives or market structures need improvement to ensure that the politically desired investment volume comes forward (EU Sector Inquiry, 2006).

Table 1 Congestion revenues from interconnectors

Congestion revenues and total investments in interconnectors during 2001 - 2005 in mln-euro		
TSO	Congestion Revenues (2001 - 06/2005)	Interconnection Investments (2001 - 06/2005)
A	200-300	25-35
B	0-20	0-10
C	80-150	0-10
D	200-300	0-10
E	200-300	50-100
F	80-150	0-10
G	20-80	0-10
H	80-150	80-150
J	0-20	10-40
K	0-20	10-40
Total	**1000-1300**	**200-300**

Source: Energy Sector Inquiry 2005/2006.
Note: Excluding spending on congestion relief.

According to answers from TSOs these revenues are mainly used to reduce national grid tariffs (EU Sector Inquiry, 2006). Since the existing interconnections were financed in the past by tariffs paid by the local consumers it seems reasonable to allocate the revenue resulting from auctions to these consumers.

In the Sector Inquiry some TSOs also provided information about recent studies on new interconnection lines. Most of these studies conclude that building a new line is a difficult and lengthy procedure and in some cases the impact on the available interconnector capacity would be low compared to the cost involved. This is partly due to the fact that in many cases increasing the level of cross-border capacity also requires substantial internal grid reinforcements (EU Sector Inquiry, 2006).

[25] Article 4 Regulation (EC) 1228/2003.

4.1.3 Investment

The Directives and Regulation indicates that the TSO may be involved in the new investment transmission capacity. For example, Article 11(5) of the 2003 Directive states that the Member States "may require transmission system operators to comply with minimum standards for the maintenance and development of the transmission system, including interconnection capacity." Furthermore, the transmission tariffs "shall allow the necessary investments in the networks to be carried out in a manner allowing these investments to ensure the viability of the networks" (Article 23(2) Directive 2003/54/EC).

There is, however, no established procedure in the Directives or Regulation for proposing, planning and approving a transmission project. It is up to each member state to adopt its own process. The typical procedure is for the TSO to provide evidence to the national regulator that a project is necessary and economic and therefore should be included in the regulated asset base.

4.2 The Special Regime for Merchant Investment

This discussion of the European transmission regulations makes clear that the base assumption is that transmission is a regulated service. Merchant interconnection does not seem to fit into this framework. For an entrepreneur to finance merchant transmission investment either long term contracts or revenues from short-term capacity auctions are required. Both are at odds with above described open access regime. For this reason, the Regulation has created the possibility of a special regime for interconnectors if they can be shown to be beneficial to competition and European integration.

The starting point of this special regime is the exemption condition under Article 7 of the Regulations. In particular, new direct current interconnectors may, upon certain conditions, be exempted from the provisions of Articles 20 and 23(2), (3) and (4) of Directive 2003/54/EC (conditions for regulated third party access) and Article 6(6) (conditions for collection of congestion revenues). These conditions for exemption are:

(a) the investment must enhance competition in electricity supply;

(b) the level of risk attached to the investment is such that the investment would not take place unless an exemption is granted;

(c) the interconnector must be owned by a natural or legal person which is separate at least in terms of its legal form from the system operators in whose systems that interconnector will be built;

(d) charges are levied on users of that interconnector;

(e) since the partial market opening referred to in Article 19 of Directive 96/92/EC, no part of the capital or operating costs of the interconnector has been recovered from any component of charges made for the use of transmission or distribution systems linked by the interconnector;

(f) the exemption is not to the detriment of competition or the effective functioning of the internal electricity market, or the efficient functioning of the regulated system to which the interconnector is linked.

Note that condition (c) does not require ownership separation but only that the interconnector be legally unbundled from the system operators. As discussed in Section 3.2.3 this may be a problem in that the SO may have an incentive to distort dispatch to favor maximizing congestion rent on the interconnector. Condition (b) presumably relates to the regulatory commitment problem discussed in section 3.1.1 above. This is the idea that regulators may, due to political or other pressures, lower regulated returns if they are abnormally high but do not offer help if returns turn out to be abnormally low. However, while MTI is not exposed to regulatory risk with return to regulated tariffs, it is still exposed to changes in market rules or other impacts from new regulation. Also, MTI is likely to be exposed to greater commercial risks than that under regulated investment. On balance, a potential reduction in regulatory risk might be more than offset by an increase in commercial risk (Brunekreeft, 2005). An important question is whether the market design (including contract markets) handle this commercial risk efficiently.

Also note that there is no supporting details on condition (a) – enhancing competition in electricity supply. Does the competition criterion apply to one side only or on both sides or competitiveness overall? Does the test assume equal social weight for consumers and producers? Should the test capture the decreased regulatory costs which may be associated with increased competition? Do we measure competition based on residual supply indices, Cournot simulation models, supply function equilibrium models or something else? It is also undefined whether in this evaluation the effect of welfare redistributions between consumers and producers and across regions should be considered (see section 2.1)? That said, most interconnectors that are not owned by incumbent generators are likely to increase competition in that they increase the size of the market and hence the number of different companies that can effectively compete with each other, so it is primarily a screen to discourage incumbent generators with market power from increasing the volume of electricity over which they have control through ownership of or contracts with the proposed interconnector.

A further difficulty is that demand elasticity may be low implying that the pure welfare effect, excluding redistribution aspects, of increased competition would be rather small, which seems counterintuitive. There might be other aspects that should be considered in such an assessment: First, increased competition should decrease regulatory costs. Second, market power distorts prices resulting in excessive entry, wrong choices of technology or locations. The costs of the excess entry can be high measured by the capital cost of the entering plant over the period until new investment would be justified. Third, underlying the analysis above is an implicit assumption of equal social weight for consumer and producers. It is sometimes argued that there should greater value placed on consumer surplus gains over producer surplus gains[26]. Higher relative social weights for consumers should, ceteris paribus, increase the value of the competition effect in lowering prices. Finally, there is the general proposition that competition stimulates innovation, cost reduction, and the temptation of political interference – a proposition for which there is good evidence from the more successful liberalisation experiences. The Regulation follows general competition law in supposing that any increase in competition is almost always likely to be advantageous, and the exact extent (provided positive) does not need to be accurately measured.

These exemptions can only be granted by the national regulatory authority on a case-by-case basis. The exemptions are applied to "new interconnectors", defined as a transmission line which crosses or spans a border between Member States and which connects the national transmission systems of the Member States, not completed by the date of entry into force of the Regulation (4 August 2003). It also shall apply to significant increases of capacity in existing interconnectors. The authority that has to decide upon the request for an exemption is the (national) 'regulatory authority', which means the regulatory authorities referred to in Article 23(1) of Directive 2003/54/EC: the authority which is responsible for fixing or approving at least the methodologies used to calculate or establish the terms and conditions for network access.

As exemptions can only be granted to *cross-border* interconnectors, so generally two countries are involved, it seems odd that the Regulation uses the phrase '*The* regulatory authority may […] decide on the exemption'. However, any exemption decision shall (only) be taken by a regulatory authority after consultation with other Member States or regulatory authorities concerned. There is no mention regarding non-member states. In this way, some cross-border co-ordination concerning the future regime for a proposed merchant interconnector is secured. Moreover, the exemption decision(s) must be notified to the European Commission, which may request that the regulatory authorities concerned amend or withdraw the decision to grant the exemption. If the regulatory authority or the Member State concerned does not comply with the Commission's request, a final decision shall be taken in accordance with the 'comitology procedure'. This check by the European Commission provides an additional instrument of European coordination with respect to merchant interconnectors.

[26] See section 2.1 for a discussion of consumer and producer surplus.

The Directorate-General for Energy and Transport (DG TREN) of the European Commission has published an explanatory note on the exemptions from certain provisions of the TPA regime (DG TREN 2004a). Although this 'note' is neither binding on the Commission nor on the Member States' authorities, it can probably contribute to a more harmonised approach to the exemption decisions. The need for a case-by-case consideration of any exemption secures at least an *ex ante* test of the benefits of the merchant interconnector concerned. In addition, the large discretion given to the deciding authority allows for a tailor-made solution for each merchant interconnector (Knops et al, 2005).

The exemption can be granted in several ways:

- The exemption may cover all or part of the capacity of the new interconnector, or of the existing interconnector with significantly increased capacity.
- The exemption may have conditions regarding the duration of the exemption and non-discriminatory access to the interconnector.
- The exemption may be only for be third party access but not on congestion revenue collection or vice versa.
- The relevant authority may approve or fix the rules and/or mechanisms on the management and allocation of capacity.

4.3 Interconnection Management Developments

A crucial element in any development of interconnector capacity in Switzerland will be the way in which congestion is managed across interconnectors. At present, interconnector capacity between European countries could be allocated in a more efficient way with appropriate structures in the different coutries and/or in inefficient amounts. The cross-border capacity which is made available is restricted by the application of security margins that are larger than would be necessary in an integrated market. This is due to a number of reasons including the fact that contractual arrangements for international electricity trading do not reflect any resulting loop flows. In searching for improvements there is now an intense European debate over whether market coupling (also called market splitting) would be a workable model for Europe. The alternative, favored by some parties, is a move towards increasingly refined coordinated auctions to manage cross-border trade within Europe. In this section we briefly examine the current ways in which interconnection congestion is managed in Europe and look at the suggested proposals to improve the situation.[27]

Figure 2 shows the types of cross-border congestion management employed in the EU in 2004.

[27] For a more detail analysis of the current state of interconnection management see Turvey (2005b), Frontier (2004) and Brunkereeft et. al. (2005) upon which this section partly draws.

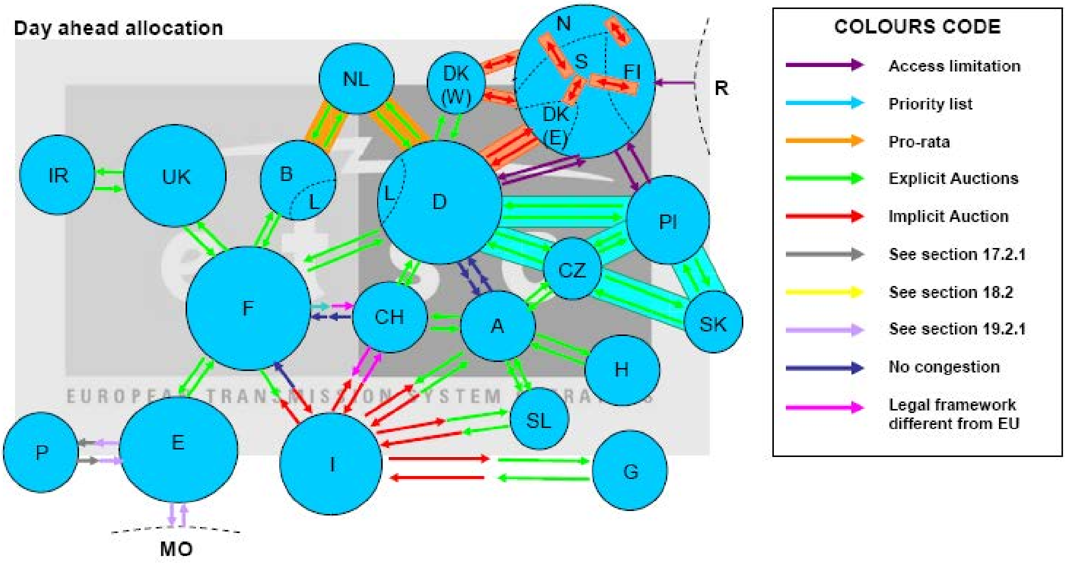


Figure 2 Congestion management between European countries (ETSO, May 2006)

In Europe the Regulation requires that market-based mechanisms be used to allocate scarce transmission capacity on congested links. As noted earlier, the theoretical optimal solution is nodal pricing, successfully applied in parts of the US East coast.[28] But as also noted, it also requires centralization of system responsibility, which is currently perceived as difficult to achieve on all European level similar to the difficulties the US federal energy regulator faces when suggesting a homogeneous market design for all US states. System operators are responsible for system balance and constraint management of their regional/national network, and they argue that only they can provide the required system security. Not surprisingly, they want to retain this authority. System operators currently determine bilaterally the amount of transmission capacity made available between neighboring countries for commercial transactions. If demand exceeds the available capacity, then auctions can be (and often are) used to make this capacity available to the market.[29]

A shared perception is that the current decentralized auctions of international transmission capacity fail to make effective use of a highly meshed and integrated electricity network.[30] For example, if electricity is transmitted from Switzerland to Germany then energy not only flows along the direct links between the countries, but also across the interconnector from Switzerland to France and then flows directly to Germany as well as via Belgium and the Netherlands (see figure 3). Currently many system operators do not receive timely information on international flow patterns to which their country is not a direct counter party. They therefore have to be conservative in issuing commercial transmission rights, because they have to anticipate the largest possible impact of the unknown flows from other international transactions. Most of the time the flows will not have this large impact, so the network is underutilized even when there is a scarcity of commercial transmission rights. This could induce the system operator to apply less conservative estimates, which could jeopardize system security if large transmissions between various countries coincide. The lack of proper coordination creates additional difficulties as the share of intermittent generation from wind increases, where generation can change dramatically on time scales that are short compared to the allocation procedure for interconnection capacity.

[28] PJM and New England. Note that although PJM has adopted nodal pricing to make better use of the transmission system within PJM, this does not solve the problem of trade across the boundaries with other TSOs – the so-called "seams" issue - nor does it ensure that efficient interconnector investments will be undertaken across these seams. See Joskow (2005).

[29] Examples are Germany-Netherlands or UK-France. See e.g. Newbery and McDaniel (2003). See also auctions between Switzerland-Germany and Switzerland-Austria http://www.etrans.ch/services/online/auctoff/index_html?set_language=en&cl=en

[30] ETSO (2001), European Commission (2003), Boucher & Smeers (2003)

Figure 4 illustrates potential evolutions from today's arrangements depicted at the left side. Currently either a coordinated auction for all European interconnector capacity or market coupling between European electricity markets is being considered. Eventually the benefits of effective use of transmission capacity might overcome the institutional and political constraints and move the system towards nodal pricing

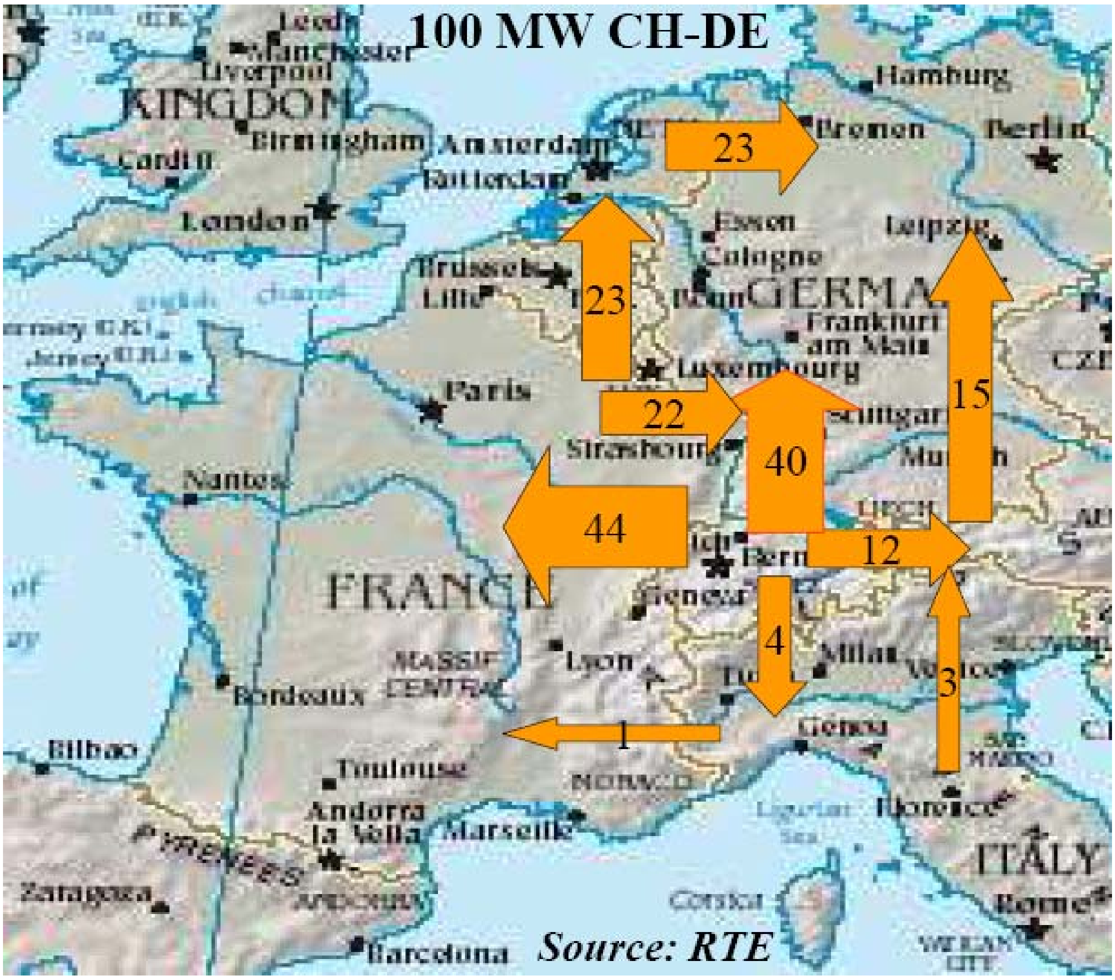


Figure 3 Impact of 100 MW flow from Switzerland to Germany

The coordinated auction consists of three steps: First, each system operator has to inform the central auctioneer about the transmission capacity available for commercial flows on its transmission network. Second, market participants submit bids for transmission rights between any two countries. Third, the auctioneer allocates available commercial transmission capacity to the bidders using an algorithm that maximises the revenue of the auction while using all available capacity. Based on the submitted information this offers a well-defined and non-disputable allocation. The auctioneer effectively considers the interests of both the bidders for transmission capacity from France to Belgium and France to Germany when determining the optimal set of international transmission rights he issues. The auction revenue can either be allocated to some sharing rule, or attributed to the individual network constraints according to their scarcity value calculated in the auction process.

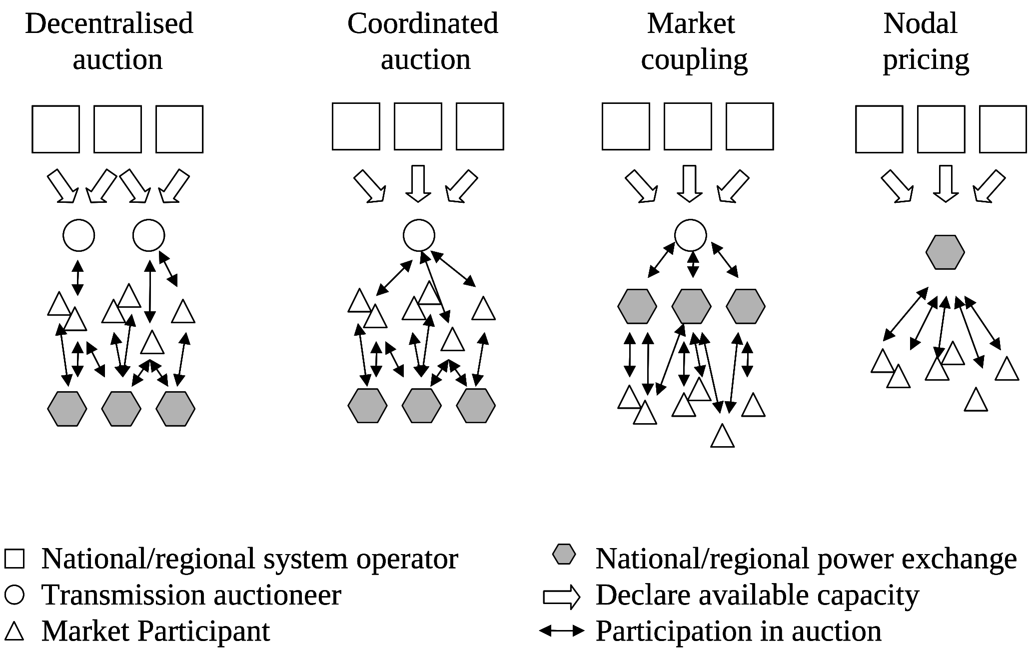


Figure 4: Different allocation mechanisms for scarce transmission capacity

The market coupling (sometimes called market splitting[31]) approach works in a similar way. Once again, each system operator has to inform the central auctioneer about transmission capacity available for commercial flows on the transmission network. However, instead of market participants bidding for cross-border rights, this time the national power exchanges submit bids to the central auctioneer. Each national power exchange would add all bids and offers to create a net demand curve, which is submitted to the central auctioneer. The net-demand curve specifies at which price the national market would be balanced (the current market clearing price) and what amount of energy would be available for exports at higher prices or required from imports at lower prices. Analogous to the coordinated auction the central auctioneer uses the typical nodal pricing method to determine the optimal use of the commercially available capacity between countries. He issues transmission rights to the national power exchanges to implement this solution. The national power exchanges then clear the local power exchange given net imports and exports and determines the market clearing prices for all locations. The revenue the central auctioneer receives from the transmission rights can be used as described in the coordinated auction.

The advantage of market coupling is that energy transmissions are determined after generators and demands have submitted their information to national power exchanges. This allows for the use of all available information and improves on the efficiency of production and allocation decision. For instance, Joskow (2003, p. 21) notes that where energy and transmission-capacity markets were not integrated (like California and Texas) congestion costs appeared to be too high, making a case in favor of integration. Neuhoff (2003) uses the explicit auction between Germany and the Netherlands and the market coupling between Sweden and Northern Norway for a test that supports the hypothesis that explicit auctions allow for more exercise of market power because generators face lower effective demand elasticities than under market coupling. In a numerical model of the meshed network of the Benelux countries, France and Germany, Ehrenmann et.al. (2003) show that market coupling would reduce prices relative to a coordinated auction of interconnectors. A potential additional benefit of market coupling is that all transmission allocation is firm so that counter-flows allow an effective use of the network. This is also possible if physical transmission rights are formulated as obligations, but currently their implementation makes them look more like options than obligations and it is unclear

[31] In practice there might be a small difference between both approaches. Market coupling or zonal pricing algorithms typically search for regional prices that clear the regional energy markets given the available transmission capacity. In contrast, market splitting first attempts to solve the integrated market, and if this results in infeasible energy flows splits the market area along predefined boundaries. Due to non-convexities introduced by discrete bid volumes and block bids both algorithms might not converge, and could provide solutions that slightly differ.

whether this situation will change. Options reduce the amount of capacity that can be safely allocated relative to obligations which can offset other flows.

Physical versus financial transmission contracts

A physical transmission contract offers the right to transmit energy between two zones. In order to allow the system operator to make effective use of the transmission network (e.g. by scheduling counter flows) the physical transmission contract should be formulated as an obligation to transmit energy.

A financial transmission contract (FTR) pays the price difference between the energy market prices of two zones. An FTR offers the same opportunities as physical transmission contracts. To replicate a physical transmission contract with a FTR a market participant sells energy in the spot market of the origin of the transaction and buys energy in the spot market of the destination. The FTR then compensates for the price difference between both spot markets.

The additional advantage of an FTR is increased flexibility. If additional transmission volumes are required, then these can be secured by trades in the local energy spot markets. Trading parties are not hedged against the price difference between markets for the transmission not covered by FTRs. Compared to a situation of physical transmission contracts this constitutes a smaller cost. If the parties schedule a transmission flow without a corresponding physical transmission contract then the flow could destabilize the system – and is appropriately so exposed to penalty payments.

To ensure that the system operator is not exposed to financial risk from the issued FTRs their aggregate volume should not exceed the physically available transmission capacity. This has the beneficial feature that in the case of an unanticipated change of market design, the FTR can be reconfigured into a physical transmission contract and its value is thus well defined. It is sometimes argued that physical transmission contracts provide additional security during times of energy shortages, as they could ensure the right to continue delivery of energy even if some demand is disconnected. However, this feature can equally be added to financial transmission contracts thus ensuring that owners of FTRs get the right to deliver their contracted energy. This is for example required under the deliverability criteria to allow participation in the capacity markets in the North East of the US.

Both proposals for coordinated auctions and for market coupling currently discussed in Europe rely on the assumption that congestion is an international issue and ignore congestion within countries. There is growing interest in market coupling that would integrate the energy and transmission markets between France, Belgium and the Netherlands.

Creating only zonal prices (Sweden) or facilitating bilateral contracting by ignoring transmission constraints in the energy market (as in UK) creates perverse incentives for the location of new generation. Thus a generator in the frequently export-constrained North of Sweden/UK first gets the national energy price, and then further profits in the balancing market when his re-dispatch bid is accepted by the SO that has to resolve constraints. The lack of explicit congestion treatment thus gives the wrong investment signals (Neuhoff, 2002). In addition generators may bid strategically to create congestion, as occurred in the US with zonal pricing, but it would equally apply to coordinated auctions.[32]

Another way to describe the relative merits of market coupling over coordinated auctions is that because all markets are cleared simultaneously, the auctioneer can make more transmission available and hence reduces the extent to which individual generators are able to exploit congestion constraints, which fragment markets and increase volatility. Harvey and Hogan (2003) address the question of whether to subdivide zones to address internal congestion. They show that the impact of market power is weakly smaller if zones are split up instead of using the system operator to re-dispatch generation to resolve the constraint and maintain a single price. Splitting up zones in an explicit auction

[32] The so-called Inc-Dec game, attributed to e.g. Chao H.P., S. Peck, S. Oren, R.B. Wilson (2000) Hirarchical Efficient Transmission Pricing, Mimeo, EPRI, Stanford University and University of California, Berkeley.

design requires that any transaction between the subzones is exactly matched by corresponding physical transmission contracts, increasing contract complexity and reducing liquidity.

With market coupling subdividing zones is less critical. First, financial transmission contracts would only be required if the risk of price differences is perceived to be significant. Secondly, financial transmission contracts between the subzones could be defined over longer periods, as most of the price risk can be hedged even if not every energy transaction is exactly matched by transmission contracts. This suggests that market coupling is preferable.

Finally, from the perspective of market participants, financial transmission contracts offer the same services that they would expect from physical transmission contracts. Assume a German generator sells to a Dutch industrial load and the price difference is hedged with a transmission contract. How will they subsequently use the contract? If they own a physical transmission contract, they will nominate the generation and exports in Germany, present the transmission contract, and nominate the imports and demand in the Netherlands. With a financial transmission contract, they will offer generation at any price in Germany and then bid for the corresponding load at any price in the Netherlands. They will be exposed to the price difference of the two markets, which is exactly covered by the financial transmission contract. They can actually improve on this with financial contracts, as bidding avoidable cost for generation allows a cost saving if the market-clearing price in Germany is below the avoidable cost, for the load will still be served in the Netherlands.

Why are European governments not willing to implement nodal spot pricing (or the simplified version of market coupling) as the logical congestion management scheme? Pérez-Arriaga & Olmos (2005) argue that the number of control areas in Europe (17 to 27 depending on where the borders are drawn) is significantly smaller than in the US with some 200. However, nodal pricing systems continue to integrate neighboring states, by now PJM alone covers 14 states and 134GW peak demand, compared to 9GW peak demand in Switzerland and 80 and 82 GW in Germany and France. This may reduce the need for a single integrated solution in Europe. Moreover, as the control areas are larger and their boundaries tend to coincide with country borders, the European member states may have a stronger political voice than the states in the US (though see Joskow, 2005, for a discussion of the difficulties to find a harmonized approach in the US context). Lastly, because the interconnections between control areas are the 'weak links' of most transmission systems, the large number of control areas in the US resulted in larger benefits to efficient congestion management.

Apart from this political constraint the previous arguments all seem to favor market coupling rather than a coordinated auctions for transmission capacity. However, the implementation of market coupling requires the coordination of a large group of stakeholders. Initially TSOs were concerned that they would loose some operational control with market coupling, and argued that this could jeopardize the security of network operation. Now it is acknowledged that market coupling allows TSOs to retain the same operational autonomy and improved information about flow patterns created by market coupling might result in a combination of better utilisation and more secure operation of the network. Organizations involved in energy trading might prefer auctions, as they provide trading opportunities and the uncertainty involved increases trading margins. However, firms (among them TSOs) interested in merchant transmission investment and generation companies considering the location of new investments are affected by the likely instability of future regulation if an unsatisfactory market design (such as coordinated auctions) is implemented. Moving towards the most efficient solution thus reduces regulatory risk.

Given that a full European nodal approach is currently some distance from political reality, could an incremental approach via regional market coupling be pursued? Could market coupling be introduced into smaller areas and then gradually extended e.g. starting with the Benelux and then extending to neighboring countries? This might require that most expansions are Pareto improvements for the relevant decision groups. Neuhoff (2003) shows that coupling of the Belgian and Dutch markets should not increase prices on either side if the same constraints on the exercise of market power remained after market coupling is implemented. This is, however, a strong assumption, discussed by Neuhoff and Newbery (2005). Where, as in Belgium, there is only one dominant generator, it is obvious who is responsible for any market manipulation, but in an integrated market with modest a number of generators, market manipulation cannot so easily be attributed to any single firm, and tacit collusion may be a problem requiring more intense market monitoring than before.

Many of the principles of nodal pricing set out in the FERC SMD are economically sensible[33] and where implemented could provide lessons for Europe, particularly if their experience demonstrates the superiority of a market design that could be replicated in Europe and is compatible with efficient market integration. The main concern is to avoid choices in the short run that make it difficult to move towards an efficient system of cross-European pricing and use of the full interconnection capacity.

According to an April 2005 paper entitled "*Issues Arising at the Regional Mini Fora Observations by EuroPEX*", the emerging pattern seems to be as follows:

- Market coupling between the markets along the western seaboard of Europe –from Norway to the Iberian Peninsula. Both PXs and TSOs are heavily involved in the process.
- Coordinated explicit auctions in Central Eastern Europe. The TSOs are driving the process here. This may eventually evolve into a flow-based approach and may also eventually lead to day-ahead implicit auctions (i.e. market coupling or market splitting).
- Italy is doing its own thing.
- Germany is acting as the central link across Europe, based on explicit auctions (strongly supported by the German TSOs) in the monthly and annual horizon and further development of the explicit auctions into effectively implicit auctions in the day-ahead market.

4.4 Harmonisation of Intra-day and Balancing Markets

As this discussion indicates, an important way in which congestion can be managed and interconnectors used more efficiently is by introducing cross-border trade and greater coordination between balancing markets. For Switzerland, there may be also trading opportunities in which the value of her hydro resources are more fully exploited.

In the EU Sector Inquiry (2006), one of the key complaints from the respondents in the European sector inquiry is that parties involved in arbitrage between borders face important differences between the administrative rules underlying the electricity markets. For instance the imbalance settlement period (for TSOs to balance the market) limits the possibility to alter schedules. These differences in settlement periods result into increased risks and are therefore barriers to trade. To illustrate one of the differences in national balancing market designs, Table 2 shows the different time periods for settlement.

[33] Although many have been criticised and may not be politically feasible.

Table 2 Timing problems in integrating balancing markets

Different time windows in which imbalances are settled by control area - 2004	
Country, responsible TSO(s)	Time unit
Netherlands (TenneT) Italy (GRTN) Austria (APG, TIRAG, VKW-UNG) Germany (EnBW TNG, E.On Netz, RWE TS, Vattenfall ET) Belgium (Elia) Luxembourg (Cegedel)	15 minutes
France (RTE) England & Wales (NGT)	30 minutes
Poland (PSE-Operator) Sweden (SK) Norway (Statnett) Denmark (Energinet.dk) Slovenia (ELES) Spain (REE) Greece (HTSO/DESMIE)	60 minutes

Source: ETSO (2004), DG Comp.

The benefits from linking intraday markets and balancing arrangements are likely to derive from a combination of factors[34]:

- **More efficient use of flexible resources.** At present, if there are no linkages between intraday markets or balancing arrangements, then low cost flexible generation resources in one country may not be utilised, while more expensive resources are utilised in a neighbouring country either by participants to fine tune their portfolios given latest expectations of their purchase and sale positions, or by the System Operator to balance their supply and demand position or to resolve transmission constraints. Clearly, in this situation, provided there were no binding transmission constraints between the two systems, greater linkage of short term markets should reduce the overall costs of serving demand across the two systems. This effect might be expected to be most pronounced where there exist neighbouring systems with different fuel mixes – for example, a thermal system or a system with significant wind capacity interconnected with a system with a lot of storage hydro or open cycle gas turbine capacity. At the same time reducing the barriers will increase the utilisation and the value attributed to the flexible hydro resources provided by Switzerland.

- **Reduced exercise of market power**: to the extent that, as a result of barriers to intraday and balancing interaction, generators within national systems are able to exercise market power either as a result of their location or their flexibility, removing barriers may increase the competitive constraints on such plant. These benefits should then be passed on to customers through a combination of retail competition and the regulatory regime applied to the System Operator. Of course, market power issues may remain within individual balancing regimes.

- **Allowing parties to create a hedge to imbalance exposure**: it may also be that exposure to volatile imbalance prices is creating a barrier to entry in some markets (e.g. to the market for retail to small customers or to the generation market) in some countries. To the extent that allowing parties with generation in Country A to receive payments related to the provision of balancing services in Country B (the prices for which typically form an input to imbalance prices), then by providing a hedge to imbalance prices, a generator in Country A may perceive

[34] Frontier Economics (2005)

a lower risk associated with entry into Country B. Much would depend on the extent of correlation between potential balancing payments and the potential imbalance price exposure – which may be low for a number of reasons[8]. However, even in the absence of a perfect hedge, to the extent that increased international linkages lead to a “deeper” set of balancing options and hence less volatile balancing (and consequently imbalance) price, the barriers to entry may be reduced.

- **Cross-border redispatch**: transmission constraints, especially when these occur close to a border of a TSO’s control area, may be most efficiently resolved by adjusting generation on both sides of the border. This requires a process that allows the TSOs involved to instruct reserve (ideally with respect to its location in the grid) in a coordinated way, relying on integrated or at least harmonised balancing markets on each side of the border.

As renewable resources, such as wind, grow in importance, the demand by TSOs and market players for access to flexible, fine-tuning resources such as hydro will grow. Already, wind is clearly having an impact on German grid management and even influences flows as far south as Switzerland (perhaps not surprisingly given the meshed flows noted in figure 3 above).

In the current market arrangement, TSOs retain transmission margins to accommodate loop flows that could result from national and international balancing transactions. Discussions continue as to whether to retain some spare transmission capacity for intra-day and balancing transactions or what other approach to choose as a more formal definition and use of transmission capacity develops.

Some guidance could be drawn from market designs like PJM in the North-East of the US. PJM not only differs from European approaches by applying nodal pricing, but also by implementing a consistent treatment of the different time frames. Day-ahead bids are financially firm, and thus permit hedging, but bids of plants are used up to real-time to optimise dispatch, and any deviations from the day-ahead and real time schedule are priced at the real-time price. Thus in the balancing market the least cost solution for balancing the system, given the transmission constraints, is implemented. In various European countries the TSOs currently contract day ahead or even over longer time frames for balancing services. In this case one would assume that a market participant can only provide balancing services to a region to which he holds transmission rights. However, it seems more appropriate to look at the parallel evolution of balancing markets and congestion management to identify pathways of improving the efficiency of the system that ensure system security, economic viability and political acceptability. This is, however, beyond the scope of this report.

4.5 Inter-TSO Compensation

EU regulations require the establishment of a compensation mechanism, according to which transmission system operators should receive compensation for any cross-border flow that would imply an additional cost on their horizontal network. Article (3) of the regulation states that “Transmission System operators shall receive compensation for costs incurred as a result of hosting cross-border flows of electricity on their network”. Article 3(2) specifies “the compensation shall be paid by operators of national transmission system from which these cross-border flows originate, and systems where those flows end”. The actual magnitude of cross-border flows hosted by a transmission system, as well as the magnitude of cross-border flows originating and/or ending in national transmission systems, should be determined based on measures of actual physical flows” (Article 3(5)). Finally, the Regulation gives indications that the cost of hosting cross-border flows (and hence the compensation there of) should be based on the forward-looking, long-run average incremental costs (Article 3(6)).

As the Regulation has only set out general requirements, the practical implementation has been left to subsequent negotiation and the practical details will be published in the Guideline once these have been approved. The first Europe wide ITC mechanism was introduced by ETSO in 2002 as a temporary measure following intense consultations in Florence between ETSO, CEER, the European Commission and stakeholders such as Eurelectric, representing network users, under what became known as the “Florence Process”. As discussed in section 3.1.2, a key objective of such a mechanism was to eliminate the practice of “pancaking” - whereby each TSO successively transited by a power flow charged a fee - and replace this system with a unified mechanism which ensures that network users are charged only one fee for power transport, while fairly compensating TSOs that host such transit flows.

The current ETSO ITC mechanism for 2006 is a two-step model which:[35]

(1) *Calculates compensation for each TSO and thus the total "fund".*

Compensation is based on regulated costs for assets and transmission losses on the "horizontal network" for each TSO, multiplied by a simple transit key.

(2) *Finances the fund.*

Funding consists of two components:

(i) Payment based on net flows between the ITC parties. The net flow is calculated from hourly physical (measured) values. For internal ITC parties, the hourly net flow is the absolute value of the total import flow minus the total export flow. For each country the funding is raised from the contribution resulting from national tariffs for load and/or generation.

(ii) An injection fee for perimeter countries to the ITC agreement area. The fee is 1€/MWh based on the declared export from the perimeter country to the ITC area. It is extracted from players using the border interconnectors.

'Transit' is defined as the hourly minimum of export and import for an ITC party, where export and import are the sums of physical flows (measured values) on all exporting lines and all importing lines respectively.

$T_i = \mathrm{Min}(X_i(t), M_i(t))$

where:

$X_i(t)$ = measured flow on interconnection i in export direction during hour t,

$M_i(t)$ = measured flow on *interconnection i* in import direction during hour t.

The values are accumulated and reported each month. The model compensates (third party TSO) transmission systems for transit resulting in export from a first TSO area and import in a second area. It is assumed that the exporting and importing areas themselves derive sufficient benefits (from the trading transaction and from national grid tariffs) and do not require any extra compensation.

The 'transit key' is the quotient of transit and transit plus consumption. It is calculated monthly where the consumption is taken as the official annual value of the national (or ITC area) consumption for the previous year (e g taken from official statistics or annual reports) divided by 12.

The 'horizontal network' is defined as the part of the overall transmission network, which facilitates international transmissions. A standardised auditable procedure for defining the horizontal networks is applied. Grid elements in the overall transmission network are included if they transmit at least 1 MW in at least one of a series of DC load flow calculations performed on an empty network where 100 MW is injected in and extracted from each pair of tie-lines in turn. Thus usually only voltage levels of 220 kV and above are included in the horizontal network. HVDC interconnectors are included if they are regarded as a part of the TSO grid, but merchant interconnectors are excluded.

'Regulated costs' are specified by each TSO individually and include costs for both assets and transmission losses. The specific values shall be the same as the costs accepted by the national regulators for the domestic transmission access tariffs. The total costs for the horizontal network will of course only represent a part of the costs for the entire network. The asset costs include costs for depreciation, yield, operation and maintenance, but exclude costs for ancillary services.

[35] From ETSO (2005a)

This inter-TSO compensation mechanism has undergone only minor changes over the last four years. The European Commission (EC) and ERGEG are now planning to introduce an updated method. It is outside the scope of this report to analysis the relative merits of the different proposed methods. Recent analysis by Frontier Economics (2006) and Florence School of Regulation (2005) both agree that the current ETSO model is the simplest method and is superior in terms of practicality and ease of implementation. On the other hand, it has clear conceptual drawbacks and is less accurate than other methods. A model is deemed accurate to the extent that injections and offtakes on one TSO's network create flows on the other networks in recognition of the laws according to which electricity flows, and can reflect the cost of these flows in the calculation of payments to be made between TSOs. The marginal participation (MP) method is probably the most accurate among the examined methods. However, it is also the most complex to implement and has high data requirements. It is interesting to note though that for Switzerland, the simulations ran by Frontier Economics using 2003 and 2004 flow data found the MP approach resulted in the higher net payments to Switzerland compared to the current ETSO method. For the average participation (AP) method, which is recommended by the Florence School of Regulation, the simulation found the opposite results, with Switzerland being worse off in net payments than the current ETSO method.

5 Switzerland

The section provides a brief overview of some of the salient features of the Swiss power sector.[36] This background research was conducted primarily in order to understand the features of the Swiss electricity sector that may affect the development of the regulated transmission system.

5.1 Characteristics of the Swiss Energy System

Switzerland has a population of approximately 7.5 million. In 2004, electricity generation amounted to 63.5 TWh. Demand rose to a new record 56.2 TWh in 2004, 7.3% above 2000 levels. The SwissEnergy 5% cap on electricity demand growth over the decade has thus been breached. About 34% of electricity was consumed by industry, 30% by the residential sector, 5% by the transport sector and 31% in other sectors, mainly in the services sector.

Hydropower accounts for approximately 55% of production and nuclear power for 40%. Nuclear and run of river plants are generally used to meet domestic baseload and medium load demand. The hydro-storage plants are used to satisfy peak load demand. As table 3 shows, hydro production varies substantially between winter and summer months.

Table 3. Swiss Electricity Generation, Consumption & Trade Oct 2003- Sep 2004, GWh

	Hydrological Year	Winter	Summer
Hydro	34,056	13,880	20,176
Run of the river	15,738	5,207	10,531
Storage	18,318	8,673	9,645
Nuclear	25,499	14,185	11,314
Thermal and other	2,912	1,507	1,405
Total Net Production (a)	60,004	28,719	31,285
Gross Domestic Consumption	60,032	32,475	27,557
Exports (imports)	28	(3,756)	3,728

(a) Total net production = production minus consumption for storage pumps".

(Source: SOE, 2004)

Total generation capacity is currently expected to increase only marginally from 17, 352 MW to 17,540 MW by 2010. Longer-term projections depend to a large degree on whether nuclear power will be phased-out. Switzerland has seen a number of referenda on the topic of nuclear energy. In 1990 there were two referenda: the initiative “stop the construction of nuclear power stations,” which proposed a ten-year moratorium on the construction of new nuclear power plants, was passed with 54.5% to 45.5%; the initiative for a phase-out was rejected by 53% to 47.1%. In 2003, there were two further referenda: “Electricity without Nuclear”, asking for a decision on a nuclear power phase-out, and “Moratorium Plus”, asking for an extension of the earlier decided moratorium on the construction

[36] This section is based on SFOE (2004), OECD (2005, 2006a, 2006b), IEA (2003, 2005), Etrans website (www.etrans.ch), SFOE website (http://www.bfe.admin.ch) and personal communications with the SFOE.

of new nuclear power plants. Both were turned down. The results were: Moratorium Plus: 41.6% Yes, 58.4% No; Electricity without Nuclear: 33.7% Yes, 66.3% No. The downturn in the economy has been offered as a reason for the rejections.[37] [38]

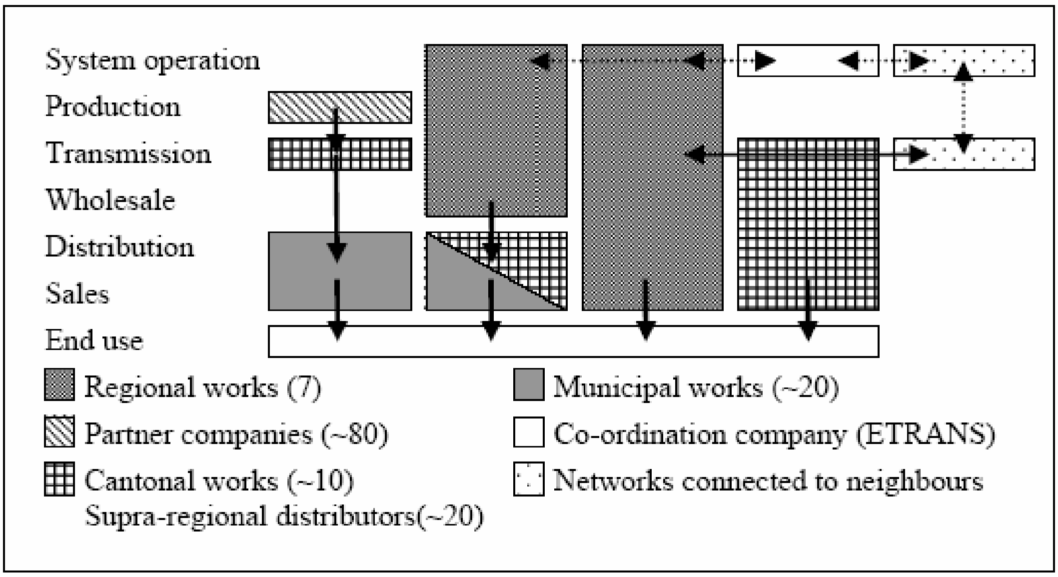
Major new capacity could stem from plans to de-mothball and retrofit the Chavalon plant by installing a 357 MW combined-cycle gas turbine. Additional generation - but not actually new capacity - is expected in 2009 with completion of repairs on the 1200 MW Cleuson-Dixence-Bieudron hydropower plant, which has not produced power since a water pipeline broke in 2000. Several major pump storage expansions of existing hydropower complexes are under way or in an advanced planning stage: Linth-Limmern (+860 MW), Oberhasli-Grimsel (+1,100 MW), Emosson (at the French border, jointly with EDF; +600 MW) (IEA, 2005).

5.2 Industry Structure

Switzerland has a large number of diverse electricity companies. There are currently approximately 900 electricity companies operating in Switzerland. The number decreased from about 1200 in the 1990s as a consequence of mergers by many small companies trying to increase the efficiency of their operations. The Swiss Electricity Suppliers Association (VSE) estimates that a further 300 mergers might take place during the next five to ten years regardless of market reform.

The differences in sizes among these 900 companies are enormous. For example, the forty largest supply companies meet more than 60% of domestic electricity demand, whereas the 500 smallest companies, some serving single townships, only command a combined market share of 10%. A large number of municipal distributors are owned by the local authority and are also responsible for other activities such as supply of water, gas and district heat supply.

Figure 5 Schematic of Current Swiss Electricity Industry



(Source: Swiss Electricity Supply Act 2004)

[37] Source: Wikipedia
[38] See Ochoa (2005) for a system dynamic simulation model of the possible effects that a nuclear phase out and liberalization may have on the Swiss electricity sector. See Filipinni et al (2002) and Banfi et. al. (2005) for an analysis of the implications of deregulation for the Hydropower sector.

The key players in the sector are the five major vertically integrated supra-cantonal companies – the so called "the big five". These are:

- Atel
- Axpo
  - o NOK
  - o EGL
  - o CKW
- BKW
- EOS
- EWZ

These utilities supply about 80% of the wholesale market. Three are 100% publicly owned (Axpo, EOS, EWZ) and the other two are in mixed ownership. All the companies generate electricity but most of them also import and export electricity and are involved in electricity distribution. In some cases, these operations are organised in different companies under the same holding company. The bulk of Switzerland's 6,500 km of high voltage lines are also owned by the big five. Table 4 summarizes their key ownership, generation and production figures. There are currently around 2,300 power plants in Switzerland, under the control of about 80 power plant operators which are mainly subsidiaries of the five main utilities (IEA, 2005).The power plant locations concentrate in the alpine region and the main rivers.

Table 4. The Big Five Electricity Utilities

Company	Ownership	Activities	Sales
Atel	Private/public ownership. 58.5% owned by Motor Columbus (which in turn is 55.6% owned by UBS bank, 20% by EdF, 10% by EOS). Remainder owned by cantonal and municipal utilities	Production: 8.3 TWh (2.5 TWh hydro, 5.8 TWh nuclear- owns 40% of Gosgen nuclear plant and 30% of Leibstadt nuclear plant) Transmission: owns 17% of the national system. "Owns"42% of transit capacity to Italy. Distribution: 9.3 TWh of sales through fully or partly owned subsidiaries and partner utilities	CHF 5.28 billion (2003) including trade (net). 68.5 TWh of which 10% domestic, 90% abroad.
Axpo	100% public ownership (cantons or publicly owned cantonal utilities). Holding company of three large utilities: CKW, EGL and NOK	Production: 30.6 TWh (22.3 TWh nuclear, 8.3 TWh hydro) Transmission: Owns major systems in north east and central Switzerland. Distribution: 14.1TWh through shareholding companies, 10.3TWh through partner utilities outside home area	CHF 5.74 billion (2003-4) including trade (net). 19.3 TWh domestic (to direct consumers in central-eastern Switzerland), 74 TWh to trade customers. 63.1 TWh trade purchases.
BKW	Private/public ownership. Main shareholders: canton of Berne 52.9%, E.On 20%	Production: 8.03 TWh (3.91 TWh hydro, 4.12 TWh nuclear) Transmission: Owns major system in canton of Berne Distribution: 6.2TWh direct sales and through partner utilities	CHF 2.95 billion (2003). 6.7 TWh domestic, 4.4 TWh abroad, 32.1 TWh to trade customers. 34.5 TWh trade purchases.
EOS	100% public ownership. Holding company of the main public cantonal and city utilities in western Switzerland	Production: 2.77 TWh (2.34 TWh hydro + 0.43 TWh nuclear) Transmission: Owns major system in western Switzerland. Distribution: 4.87 TWh through shareholding companies	CHF 1.05 billion (2004).4.87 TWh.
EWZ	100% public ownership. Owned by the city of Zurich public utility	Production: 1.4 TWh hydro Distribution: 2.9 TWh direct sales	CHF 0.6 billion (2003). 6.02 TWh.

Notes: Transmission = the Swiss high voltage grid.

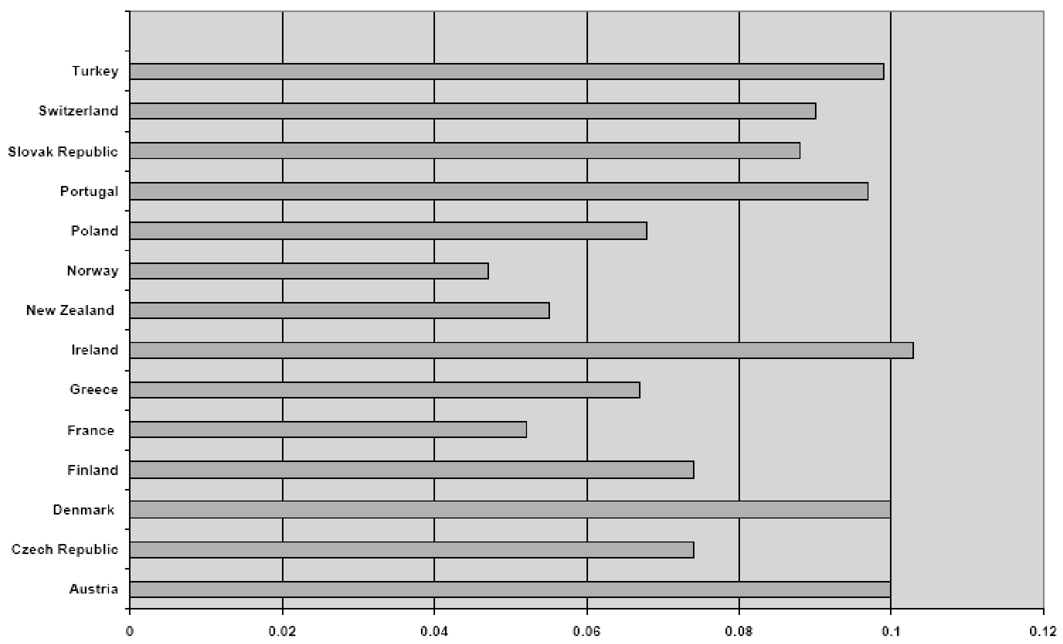
(Source: OECD, 2006b)

5.3 Retail Prices

Swiss electricity prices are set either by cantonal or communal authorities, or by companies, subject to approval by the Price Inspector. Various taxes, collected mostly at cantonal and/or communal levels, are added to the electricity tariffs.

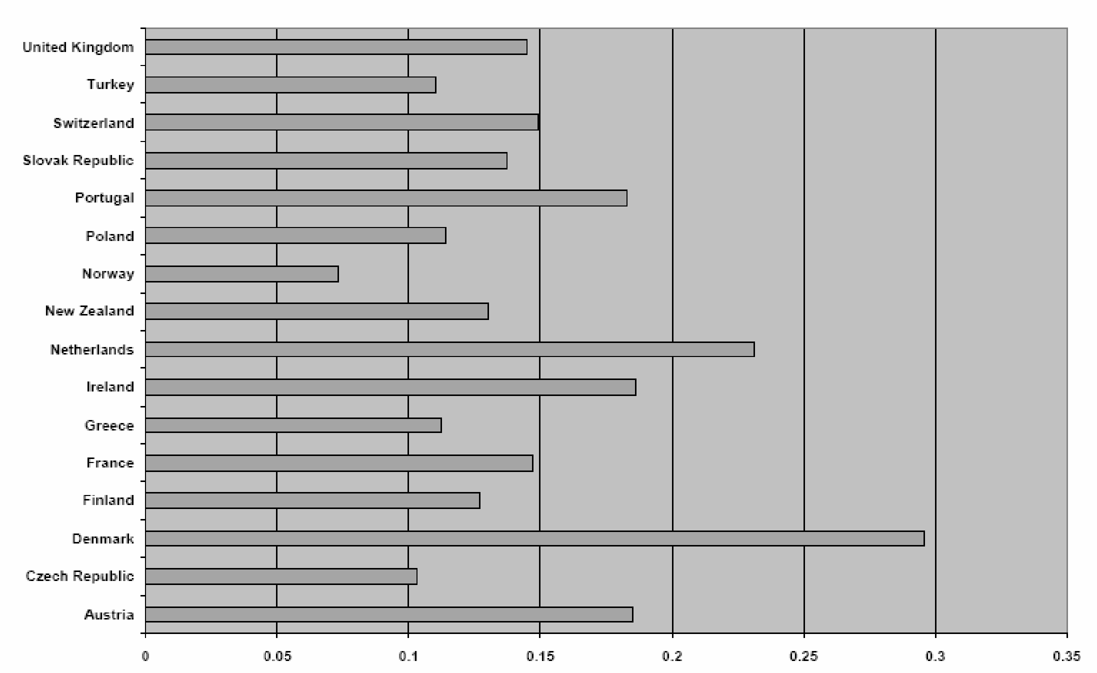
In international comparisons, prices are relatively high for industry. In 1997, the average electricity price for Swiss industry was the second-highest amongst IEA countries. In 2002, despite a considerable decrease, it was still the fourth highest, sizeably lower than in Italy but higher than in, *inter alia*, Austria, France, and Germany. In its 2003 review, the IEA still found electricity prices in Switzerland to be higher than the European average, particularly for small and medium-sized enterprises. This has been ascribed to the taxes and charges set by the cantons and municipalities. The IEA also expressed concerns about the efficiency of the operation of many publicly owned small utilities companies and their considerable profits, noting that the current price-setting mechanisms lack transparency and enable cross-subsidies from one consumer group to another.

Figure 6. Comparative electricity prices (including network charges) for industry consumers in the OECD ($US/kWh)



Source: Energy Prices and Taxes, IEA/OECD, 1st quarter 2005.

Figure 7. Comparative electricity prices (including network charges) for residential consumers in the OECD ($US/kWh)



Source: Energy Prices and Taxes, IEA/OECD, 1st quarter 2005.

Household electricity prices are only slightly above OECD average. However, the main issue for households is the high price variability among customers. The Price Surveillance Authority's Internet database highlights that average household prices vary greatly (+/- 50%) throughout the many distribution zones of the country.

5.4 Legal Frameworks

The current legal and regulatory framework for electricity in Switzerland derives from all three levels of government (federal, cantonal and municipal). At the broadest level, the federal government legislates on mainly strategic issues while the cantons have near autonomy in the manner of implementing these laws. Specific regulation is largely, though not exclusively, in the hands of the cantons and municipalities, and covers entry into generation (for power plant licences), end user prices (regulated by the cantons or municipalities and approved by local political bodies), end user supply and public service (distribution concessions or through the local authority's own utility).

The main electricity laws are[39]:

- Energy Law (1998): Policy measures for the energy sector, mainly focused on efficient energy use and renewables, and R&D. Regulates conditions of connection to the grid for certain independent power producers (small hydropower and non hydropower renewables, CHP among others).

- Law on Electricity (1902): Regulates construction and safety issues. Federal government supervises and regulates the construction and operation of electricity infrastructure, and issues safety regulations.

[39] OECD (2006b)

- Law on the use of Hydropower Resources (1916): Regulates the use of hydropower resources. Federal government oversees and issues regulations, cantons designate concessionaires. Law also sets up and regulates royalty tax on water use, levied by the cantons.

- Nuclear Energy Law (2003): Regulates nuclear power plant construction, operation, and decommissioning, and waste disposal and safety issues. Federal government in overall charge.

Two general laws are of considerable importance for electricity are:

- Cartel Law (revised in 2004): Deals with the prevention of the harmful economic or social effects of cartels or other restrictions on competition.

- Price Surveillance Law (1995): Deals with the prevention of abusive increase or maintenance of prices.

Other more general laws are also relevant, include the CO_2 Law (1999), the Internal Market Law (1995), and the Law on Economic Supply (1982).

The key federal ministry responsible for energy policy is The Federal Department of Environment, Transport, Energy and Communication (DETEC) with its key office being the Swiss Federal Office of Energy (SFOE). The Federal Inspectorate for Heavy Current Installations (ETSI) is another office of DETEC involved in the implementation of technical standards for electricity infrastructure.

Switzerland is not a member of the EU nor of the EEA. However, Switzerland is a member of the WTO, which covers electricity, and in particular the service aspects of electricity trade. However, there has been relatively little attention focused on this area. Switzerland is also a member of the Energy Charter Treaty (ECT), which may have some relevance - at least in principle - for transit regulation (OECD 2006b). Article 7(3) of the Treaty covers transit and requires National Treatment (NT). This requires that the electricity of other Charter signatories in transit through Switzerland must be treated at least as favourably as Swiss electricity in domestic transport and vice versa.

Although not part of the European Union, Switzerland clearly has been influenced by developments in the EU, and in 1999 proposed a new Electricity Market Law (EML) to introduce more competition. Key elements included:

- a system of regulated third party access to the networks;

- organisational unbundling of transmission from other activities, including the formation of a new private company to take over responsibility of the national grid to act as independent system operator (ISO);

- separation of accounting for generation, distribution/supply and non-electricity related activities;

- the creation of a new institution, the Arbitration Commission, to supervise transmission and distribution tariffs;

- power exchange with other countries based on the adoption of a reciprocity clause, but including safeguards against suppliers from countries with less liberalised electricity markets. (Grimston, 2004).

It was intended that retail competition would be phased in over a six-year period for ‘qualified consumers’.

However, in September 2002 the Swiss people rejected the EML by a margin of 52% to 48%. While originally having a broad measure of support, the unions, supported by a coalition of political interests, incumbent monopolies and environmentalists, conducted a strong campaign against it. They raised concerns over the possibility of price increases and instability and pointed to the apparent limited success of retail competition in neighboring countries.

Concurrent with this setback to competition from the failure of the EML, however, the Swiss Competition Commission was successful in ruling that negotiated third party access (TPA) could be enforced in Switzerland. The Supreme Court affirmed this position and the ruling has also upheld by the Federal Council. However, electricity companies have not been granted the right to TPA automatically, but need to secure it case by case through lawsuits.

In order to avoid the lengthy and costly process of conducting lawsuits, companies have urged the government to clarify matters with a new law. In December 2004, a new legal reform package for the electricity sector was sent to Parliament after more than a year of preparation and public consultation in the aftermath of the demise of the EML. The package includes (1) an amendment to the Electricity Law and (2) a new Law on Electric Power Supply (LEPS).

The amendment to the Electricity Law is a temporary solution until the new LEPS enters into force and is also a backup if LEPS fails to pass through Parliament. The law provides for EU-compatible cross-border electricity trade, with TPA to be offered by the newly created transmission system operator Swissgrid and regulation to be conducted under a new Electricity Commission (ElCom).

The major part of the reform package, LEPS, will implement the following measures:[40]

- Upon enactment of the law, all commercial customers will become eligible, to be followed five years later by full opening of the market. Households will be given the choice to either remain captive to their incumbent utility or to be eligible to choose their own suppliers.

- ElCom's powers will be extended to regulate not only cross-border trade, as foreseen by the amendment to the Electricity Law, but also the domestic market.

- Distribution companies will be unbundled at the accounting level, as legal unbundling would be too burdensome for most of them, as they are small utilities.

- Legal unbundling of the transmission network will have taken place previously by amendment of the Electricity Law and the setting up of Swissgrid, the TSO. To allay concerns about public service dismantlement, which caused the failure of the EML, the LEPS reinforces electricity companies' obligations regarding security of supply and empowers the Federal Council to take remedial action if security of supply is threatened.

- Cross-border auction revenue may be used by the line owners for (1) expansion of the network; (2) relieving congestion by managing generation; (3) reduced rates for consumers, or (4) given (some) back to the owners of transmission due to the risk that they have to bear. The last is a potentially important means of returning revenue to the transmission line owners.

We understand that the reforms are still being debated in Parliament and the package may still go to a referendum. However, there appears to be room for cautious optimism that the new laws will pass this time. Notwithstanding legal uncertainty, the electricity sector has already geared up for competition by granting sizable price discounts to large customers, and by consolidating and by setting up a joint company, swissgrid, to operate the transmission network. It is planned that swissgrid will success to ETRANS and become the national TSO. In March 2005, Switzerland's Competition Commission imposed certain conditions on the establishment of Swissgrid. In May, Swisselectric, the association of large utilities and the main shareholders of Swissgrid, appealed against some of these conditions. The appeal process is still ongoing and the formal establishment of Swissgrid is still unclear.

[40] (OECD 2005).

5.5 Cross-Border Trade

The geographic location of Switzerland within the centre of Europe, along with its flexible hydro resources, has made Switzerland a major hub for transit in electricity as well as a major trader. The main Swiss companies have trading subsidiaries in most of Europe. In the UCTE area, Switzerland accounts for 11% of cross-border trade and 20% of cross-border transmission capacity (OECD 2006).

Traditionally, Switzerland has been a net exporter of electricity over the whole calendar year. In recent years, however, demand has increasingly shifted towards the winter season and thereby led to increased imports. Owing to rising demand and reduced hydropower production during the hydrological year 2004 (1 October 2003–30 September 2004), Switzerland became a (small) net importer for the first time since 1971/72. For calendar year 2004, exports dwindled to 0.7 TWh - a considerable decline compared with 3.1 TWh in 2003 and 10.4 TWh in 2001. (IAE, 2005)

As cross-border net transfer capacities for imports to Switzerland in 2006 the following values have been agreed:

- 3,200 MW (3,000 MW in summer) from France.
- 2,150 MW from/to Germany in summer (2,080 MW from Germany in summer).
- 550 MW from Austria (520 MW in summer).
- 3,850 in winter, 3,120 MW in summer to Italy.

The commissioning in early 2005 of the 1,300 MW San Fiorano-Robbia interconnection should have eased the chronic bottleneck with Italy. The interconnections with France and Germany are occasionally congested in times of high load and strong loop flows. The figure below indicates a number of interconnectors, including a 400 kV DC merchant line, which are at the planning or permitting stage.

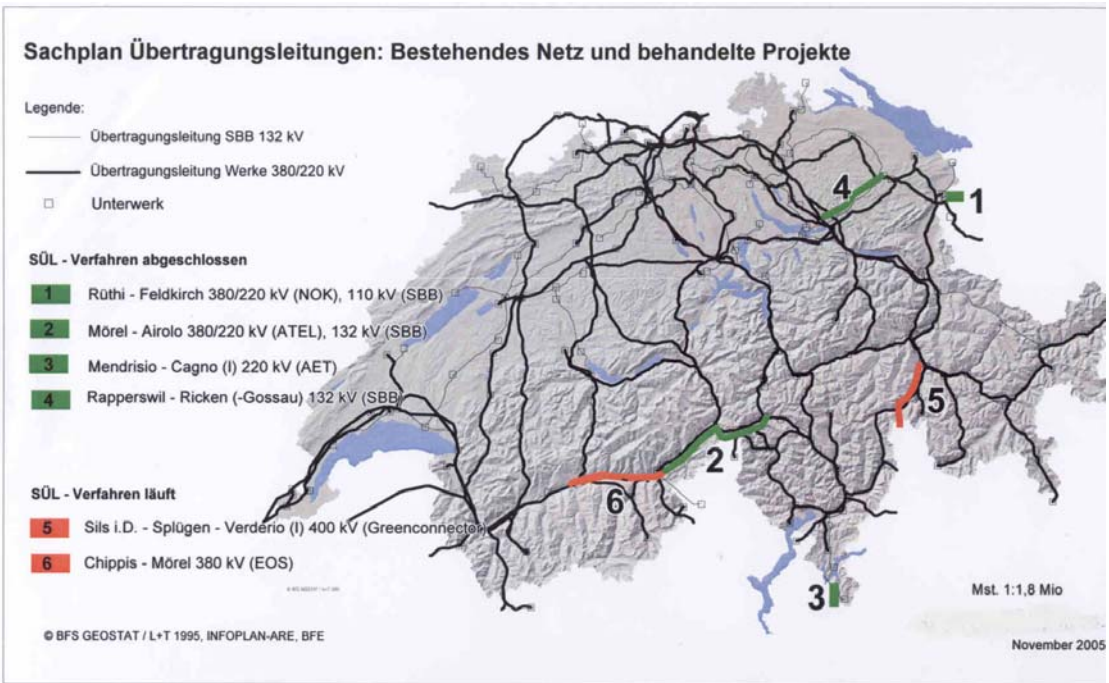
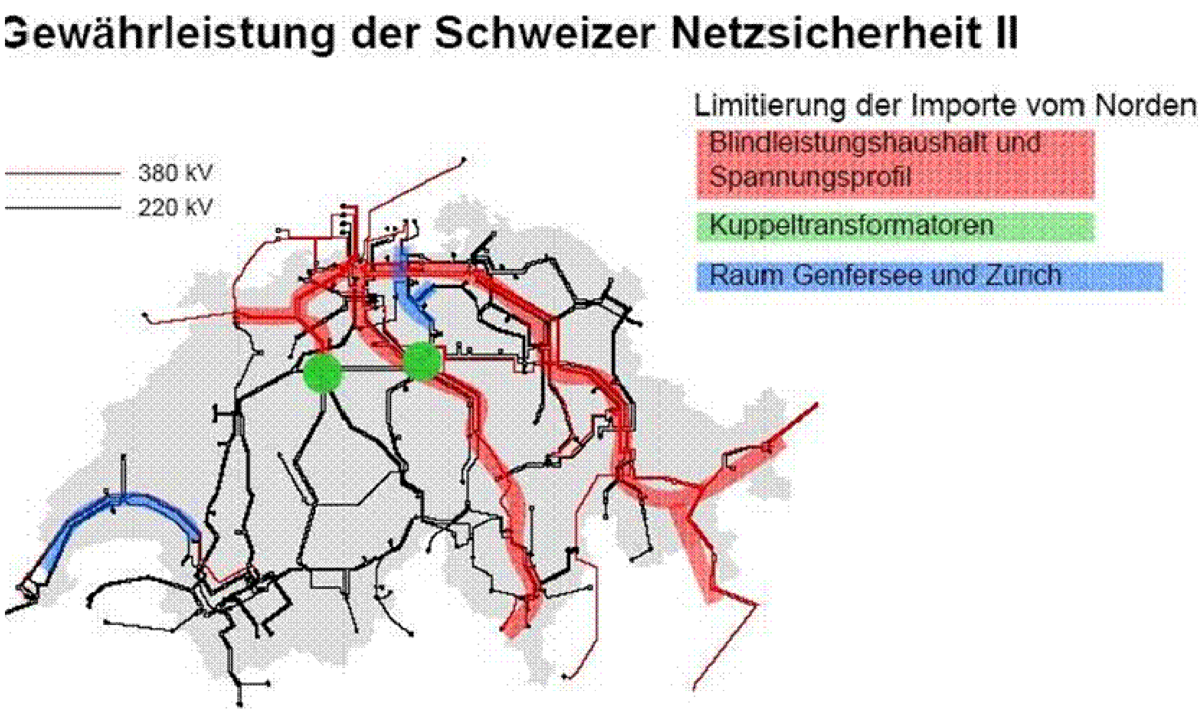


Figure 8 Transmission lines and interconnectors

An important driver of congestion management operations has come from the introduction of cross-border auctions. Along with other recent exogenous effects on price differentials, the result has been to initiate or change commercial trading patterns. This has substantially altered the load flow patterns through and within Switzerland. This is developing and Switzerland is now facing new congestion points that have not existed before.

For many decades the design and growth of the Swiss system was dominated by the North to South flows pattern: exports to Italy were only limited by how much they could import into Switzerland. But the market in Italy (and the price differentials) has already changed so much such that Switzerland is now even importing from Italy.

Another recent development has been the influence of wind from Germany via the EnBW network. During high wind periods in Northern Germany when wholesale prices drop, traders have been using these moments to export to Italy.



6 Conclusions

Switzerland already has a well-established transmission infrastructure well suited to the needs of the country.

Arguably, there is the potential for further transmission upgrades, using power electronics, capacitor banks, upgrading existing lines in voltage and capacity and constructing new lines, particularly to handle the changing patterns of flows caused in part by external developments.

In the Swiss context, these expansions could serve the following four objectives:

- Allowing a better utilisation of existing generation resources, for example avoiding the need to operate designated must-run power stations. This will reduce operational costs (fuel, labour, maintenance) and is likely to improve environmental performance.

- Providing higher value applications of the flexibility of Swiss hydro resources for balancing services in the European context. The need for this flexibility is increasing with increasing wind penetration, and thus the value provided and the corresponding revenue collected by Switzerland is increasing. Currently flexibility is restrained by must-run conditions to maintain Swiss power system stability. These must-run conditions impose constraints on the net volume of imports into Switzerland. Thus hydro resources have to run even at off-peak periods, and thus can save less water for peaking times or to provide flexible response.

- Increasing the transit capacity for Switzerland, e.g. from Germany and France to Italy, but with possibility of flow patterns in other directions (as seen recently).

- Switzerland has a strong portfolio exposure to nuclear and hydro energy. With increasing international interconnections this can be further diversified, e.g. to include more gas-based generation with increasing interconnections from Italy or coal and wind based generation with increasing interconnection with Germany.

There are some important principles that a regulator should follow in developing an MTI scheme. First they should ensure that any contract offered for an MTI does not hinder desirable future market designs such as market splitting or nodal pricing. Second, they should ensure that any MTI is dispatched efficiently. They also need to allow for any subsequent move to a regulated status. This includes publishing criteria for setting any future regulated tariff and spelling out compensation principles in case of market design changes

As the regulatory regime and market design is still evolving both in Switzerland and the neighbouring countries it is difficult to envisage in the immediate future that merchant investors will directly finance new lines based on their expected revenue from arbitraging price differences to neighbouring countries. Such investors would face significant regulatory risk.

For example, a move towards nodal pricing in Switzerland and/or in neighbouring countries like Italy and Germany would reduce revenues for projects that envisage capturing the price differences between a single Swiss price zone and price zones in neighbouring countries by building a short link across the border. Nodal prices are likely to create a gradual locational increase in price (for example assuming historic flow patterns from Germany to Italy). This would eliminate the price jump that currently is directly associated with borders between Switzerland and neighbouring countries.

Another regulatory risk previously mentioned is the possibility of subsequent additional transmission investment on a regulated basis. Given the uncertainty about the evolution of the market and regulatory regime, this is possible and could further reduce constraints and thus eliminate scarcity rents.

To avoid both issues a transmission investor is likely to prefer some long-term contract cover to create some assurance about future revenue streams. In the absence of a well-defined market design, however, it is difficult for market participants to agree and sign such long-term contracts. Also, the changing flow patterns over the last months (e.g. Italy starting to export), makes it less interesting for other market participants to contract long-term international energy flows, if wholesale price differences are no longer persistent.

It is currently widely debated to what extent congestion revenues provide sufficient remuneration for merchant transmission investment. Some studies even suggest that in an optimally designed network with efficient nodal pricing as congestion management only 25% of the investment costs can be covered as congestion revenue. This might be attributed to the fact that system security and the provision of ancillary services is not adequately priced. But without further numerical and engineering studies we could not come to a final conclusion regarding this question. Looked at another way, if MTI can earn a commercial return, that *might* be evidence of under-investment in interconnectors, and MTI might partially address such problems of underinvestment.

We anticipate that a more flexible use of the Swiss transmission network can allow Swiss hydro resources to provide increasing flexibility for the short-term operation and balancing of the European electricity network. Judging by the current prices at European balancing markets and the increased demand for such services with increasing penetration of intermittent generation sources like wind power, this could be well remunerated. Flexible and more volatile transmission flows are somewhat more difficult to contract for in long-term arrangements and it is also rather difficult to judge what the value is. Furthermore, the value allocation between hydro resources and transmission capacity is a difficult bargaining game that might hold up investment. Nevertheless, policy makers should continue to be aware of this important source of value.

To harvest this value, the importance of an efficient market design for the operation of the transmission and balancing markets cannot be under-estimated. Further improvements within Switzerland and in the European context are warranted. Switzerland is in a good position to advance this process, given the unique geographical position in the centre of the European network and its pivotal role in European energy discussions. The benefits that many Swiss stakeholders can draw from better integration of the hydro resources provide a powerful motivation for increased engagement.

It seems currently unclear how such increased integration will be reflected in the Swiss wholesale price level, given that difficulty to predict future fuel and CO_2 prices. A further investigation of the long-term contracts between generators and consumers or their representatives seems warranted, as insulating base load electricity consumption from risks induced by marginal energy prices is not only likely to improve consumer utility but could also address concerns about such risks or possible windfall profits.

Many of the projects currently under discussion are small additions to existing networks. It is unclear how their additional value could be identified, and if so, if all that value should be attributed to the comparatively small investment. Arguably, they might be in danger of free-riding on the value of the existing grid if the Swiss and neighbouring countries do not introduce connection and use of system charges and congestion management that captures network topology within the country. One might also ask whether any contractual arrangements required to allocate the value to the investor also reduce the flexibility for the Swiss government to evolve the market design best suited to Switzerland, suggesting an urgent need for regulatory clarity about the nature of any contracts (financial or physical, with use-it-or-lose-it conditions, etc).

Thus we suggest that SFEO together with neighboring countries develop a consistent network charging scheme and lay out the future congestion management and balancing arrangements as a basis for any merchant transmission investment.

To facilitate any evaluation of the value of individual merchant transmission projects within the bigger picture of future system evolution, Swissgrid could identify grid investments within Switzerland that benefit Switzerland and propose/publish plans for their realization. Swissgrid would need to co-operate with ETSO neighbours to identify and publish beneficial grid investments that have external benefits. If these projects were to be advanced as regulated transmission investment, then ETSO (including Swissgrid) need to agree on a future cross-border compensation scheme. This could include the possibility of differentiating the charges for existing grid and future expansions.

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