Transmission Investment – how to get the incentives right

PAPER FOR 6TH CONFERENCE ON APPLIED INFRASTRUCTURE RESEARCH – SUPPLY SECURITY AND RELIABILITY OF EUROPEAN INFRASTRUCTURE

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ABSTRACT

Changes in the plant structures (e.g. through nuclear decommissioning and new wind investment) could create network congestion within countries that have previously operated "copper plate" markets. This could lead to regional market fragmentation. The German government proposes to use investment budgets that guarantee the recovery of capital expenditure (CAPEX) within the new regulation design with the aim of securing investment. However, our analysis indicates that this measure may not yet be sufficient. We consider alternative schemes to raise incentives to reinforce grids in order to avoid congestion. While a model based on merchant (or merchant like) investment may appear as a good theoretical solution its effectiveness is yet to be proven in practice (e.g. in the US). Such a model is also unlikely to fit the European regulatory environment. The French or Italian approach of granting a preferential return on "strategic projects" appears effective, but is likely not efficient. A UK style sliding scale regime appears effective although significant challenges arise in its practical implementation.

1. BACKGROUND

Congestion in energy networks poses a challenge nationally and internationally:

- International - Lack of international interconnection has been identified by the EU Commission as one of the key obstacles to stronger international market integration and thereby lower market concentration.
- National - In addition, structural changes in the plant structures (e.g. through nuclear decommissioning and new wind investment) could create network congestion within countries that have previously operated "copper plate" markets. This could lead to further regional market fragmentation. Recent policy debate, e.g. in Germany, appears to focus on how to handle existing bottlenecks – e.g. by altering the dispatch of power stations – rather than on how to structurally remove bottlenecks.

In this world policy makers expect Transmission System Operators (TSOs) to undertake necessary efficient investment. However, in a world where regulators increasingly move to incentive based regulations it is less clear whether the required investments will be undertaken and what the regulatory arrangements would need to be in order for efficient investments be commercially viable and go ahead.

In our paper we explore:

1. what the basic economics of network congestion and investment are;
2. how traditional regulatory rules e.g. as that (proposed) in Germany may limit transmission investment;
3. which incentive arrangements have been employed to foster grid reinforcement;
4. what the efficiency properties of these alternative incentive regimes are; and
5. what issues arise in the practical implementation of alternative regimes.

We find that conventional regulation regimes may create an inherent bias against network investment. This is due to the fact that the TSO is held responsible for the cost of infrastructure but not other network effects -such as cost of ancillary services, losses and congestion management. This can lead to suboptimal investment decisions. This deficiency is also not healed by implementing “investment budgets” as proposed in Germany.

2. THE BASIC ECONOMICS OF NETWORK CONGESTION

Energy transmission networks physically connect the producers of energy to customer loads. For example, they link power stations to regional networks that supply electricity to end users. What is a key design principle for energy transmission networks? The social planning objective is to minimise (over time) the sum of:

- infrastructure cost (plants, networks); and
- operating cost (production cost, transportation cost/losses).

A stylised example for optimal network investment

Put simply, network investment (for a given location of production) is socially desirable if:

(1) cost of network investment < saving in power production (and transportation) cost by accessing cheaper source of supply.

In the power sector, new or relocation of power stations is an alternative to network expansion. Where this was relevant it would also need to be considered and our simplistic rule would become more complicated. It is worth asking to what extent plant relocation (for newbuilt or replacement) is a real option. It would be, if it was cheaper to locate power stations close to demand and to transport fuel (such as coal, gas, oil) to these locations rather than placing power stations more remotely from load and transporting power over longer distances. Although we are not aware of comprehensive analysis of this question in the public domain, our own internal calculations suggest that at prevailing fuel prices reinforcing networks rather than placing power stations closer to load is a cheaper option. This indicative finding gives confidence that our simple rule (1) above is applicable.

We can therefore also illustrate the basic economic logic of network investment for a stylised example (Figure 1). We consider an insular network with two power stations (A and B) and two demand regions (A and B). Demand in either region is 200 MW. The capacity of each power station is 400 MW. The power station in region A is a new efficient station with variable cost of c_A = 25 €/MWh. The station in region B is less efficient and has a variable cost of c_B = 45 €/MWh. If there were sufficient network capacity, then all power could be supplied from the lower cost station A. A power flow of 200 MW would arise from station A to region B.

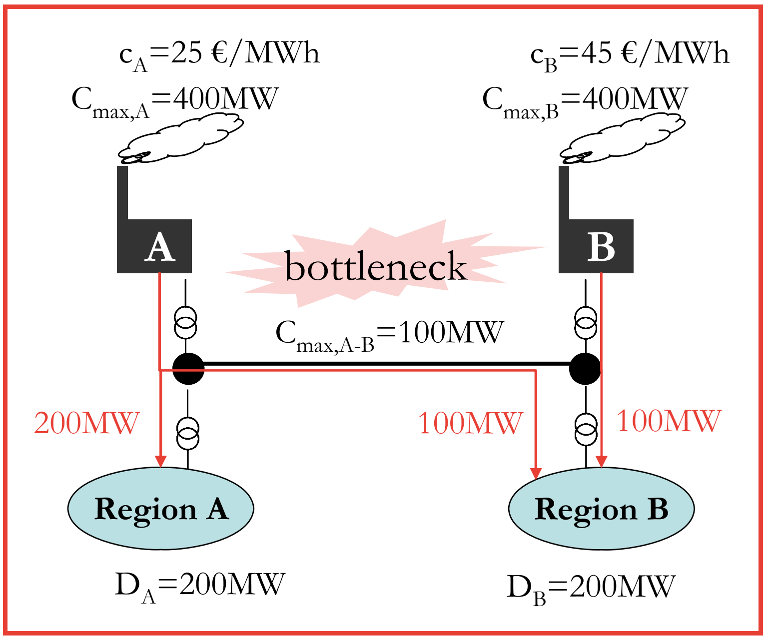

Figure 1: Network congestion (stylised example)

Now consider a situation where transmission capacity between regions A and B is limited to 100 MW. Given this constraint, 100W have to be produced in station B and output in station A has to be reduced to 300 MW. The cost difference in power production due to the need of employing the more expensive station B constitutes the cost of the congestion.

In our stylized example the congestion cost would be equivalent to the spread in variable cost between the power stations (20 €/MWh) multiplied by the redispatched capacity (100 MW). Assume that this congestion would arise in 200 hours per year (ca. 2.5% or all hours in a year), then the annual cost would amount to € 4 Mio/a.

Table 1: Congestion cost (stylised example)

1	Congestion volume	100MW (=DB – Cmax,A-B)
2	Cost spread	20 €/MWh (=35-25 €/MWh)
3 (=1x2)	Congestion cost	2000€/h

Whether network expansion to remove the bottleneck was viable given the annual cost of congestion of € 4 Mio/a would also depend on the cost of the investment. This in turn can depend on the type of required investment, e.g. whether it requires changing the voltage level of existing assets, expanding transformer capacity, the connection of additional wires to existing pylons (and the distance to be bridged), or the construction of a new circuit.

Further cost considerations in practice

Clearly, our example is very simplistic, but it helps understanding the principal economic logic for network investment. In practice further aspects will need to be considered:

- **Meshed networks** – in practice, energy networks do not take the form of point to point connections. They are rather very meshed and connect hundreds of production sources to hundreds of connection points of regional grids. This implies that power does not flow along one dedicated path but follows the path of least resistance and power flows spread over many lines ("loop flows"). Given the interaction of power injection and withdrawals it means that in order to relieve a congestion on a certain line, say by 100 MW, a significantly larger volume of power (in MW) needs to be redispatched (often, required redispatch exceeds the extent of the congestion by a factor of 4 to 10).
- **Dynamic cost of power stations** – the cost structure of power stations and therefore the cost of redispatch is more complex than presented in our simple example. Beyond the variable cost related to output, power stations also incur start up cost. Upon redispatch a plant may need to start up. Alternatively, it may already have been held in no load operation to be able to flexibly respond (in this case it incurs at least no load heat cost). Further more, if plant is operated at reduced output so as to allow it to ramp up quickly, it will typically run at lower efficiency and thereby higher variable cost. Power stations also face dynamic constraints of minimum output (i.e. output has to be zero or at a level of at least 40-50% of maximum output) and the speed of increasing and reducing output may be constrained. These constraints imply that the plant used for redispatch is not always the plant with the cheapest variable cost, but possibly a plant with higher variable cost that is capable of operating with greater technical flexibility.

- **Secondary effects on further cost elements** – the cost of congestion may not only consist of the cost of redispatch. For example the volume and cost of losses on the system is also positively related to the load and congestion on the system. Additionally, more power plant reserve for balancing purposes has to be contracted and plants with higher costs might have to be called for balancing since the geographical flexibility to respond to imbalances is diminished by grid constraints.

However, in order not to complicate our considerations we focus in the paper on the trade-off of network investment and power production cost. Our arguments easily extend to more complex set-ups.

Alternatives to investment

In considering the appropriate regulatory design it is also important to consider, that operational ("soft") measures may alternatively and efficiently serve to contain congestion cost. It may e.g. be possible to enhance network capability by:

- Improved **capacity allocation** – advanced techniques can be used to determine available network capacity. The design of efficient rules for allocating this capacity to market participants may further help improve network capability and lower congestion cost. Such measures are possible without endangering network reliability. Recent regulatory debate has shown that it can be possible to make more capacity nominally available to the market through better coordination between network operators and through market based allocation regimes.
- Improved **procurement of redispatch services** – it is sometimes possible to lower the cost of redisptach by efficiently procuring respective services, e.g. by procuring them form a wider set of plants.

- Operational **switching actions** – certain short term operational measures of the network operator may help prevent short-term congestion.
- **Scheduling of network maintenance** and co-ordination between network and plant maintenance – for example scheduling maintenance in periods of lower congestion cost can help improve efficiency.

3. THE INCENTIVE GAP IN GERMANY

With a new proposed Decree (ARegVO) Germany is on the path to revenue cap regulation from 2009. The regime is aimed at giving network operators incentives to lower cost by fixing the path of their revenues or prices for a period of e.g. five years. Companies could then raise profits by lowering their costs below target revenues.

In this section we describe the logic of the regime, develop a possible scenario of how different cost elements may be treated by the regulator and then explore possible inefficiencies in this scenario.

Features of the German regime

There are important further aspects to the German regime:

- **Investment budgets** – the authors of the decree acknowledge that the proposed revenue cap regime could lower incentives to invest and maintain or expand the system. This is because investments would otherwise raise costs without creating an extra revenue allowance. The Decree would allow network operators to pass through any capital expenditure (CAPEX) for (restructuring and expansion) investments up to the limit of an "investment budget". The investment budgets would need to be submitted by the network operators and approved by the regulator. The effect is that costs within the investment budget would be exempted from incentive regulation and rather be subjected to a cost-of-service regulation.

- **Non-controllable cost** – the German decree considers that not all operating costs necessarily lie in the control of the TSO. The Decree leaves room to exclude further costs from the incentive mechanism and to treat them as (effectively) pass-through. A debate is likely to arise around which costs should be considered as pass-through. Likely candidates for such a debate include costs of network congestion, losses, procurement of ancillary services etc.
- **Quality regulation** – the Decree also allows to include an element in the formula of allowed revenue that is linked to the quality of service. The quality regime is as yet not defined and to be developed by the regulator. The decree gives an indication, though, that the degree of network congestion (or its relief) may (but does not have to) be regarded as such a quality element.

A possible scenario for Germany

This setting could lead to the following scenario which we use as reference for our further discussion (we use this scenario not because we believe it reflects what should be implemented, but rather in order to highlight inefficiencies that could arise in an ill-designed regime):

- **CAPEX becomes pass through** – network operators would have an interest to secure repayment of investment by having investment budgets allowed. Investment budgets would be subjected to an ex ante and ex post control (revenue is only allowed if investments are actually undertaken);
- **Congestion cost becomes pass-through** – if congestion cost were deemed "controllable" they would fall within the incentivised cost base. In the long run network operators can entirely avoid these costs occurring by creating sufficient transmission capacity. In the short to medium run they can contribute to

containing congestion cost by switching measures and by appropriate scheduling of maintenance activities. On the other hand, generators or network users could contribute to containing these costs, in the long run e.g. by choosing appropriate power plant locations in the grid to help avoid congestion. Network operators will not like to be held financially responsible for costs which other stakeholders can influence. This holds especially as the cost of congestion could become very volatile. Unpublished estimates suggest that the congestion cost for Germany alone is currently almost negligible but could reach several 100 Mio €/a. Network operators will therefore rather try and avoid risks which they themselves cannot control. Network operators are therefore likely to argue in favour of treating congestion cost as "non-controllable" in the sense of the Decree. This would make these costs "pass-through".

- **Cost of losses becomes pass through** – by a similar logic, the cost of losses may be argued to be considered as "non-controllable" thus making it a pass-through item. There are some qualitative differences between the controllability of congestion and loss cost. Loss cost are likely to be less volatile and they are not avoidable altogether.
- **Only remaining OPEX is incentivised** – the described scenario would only leave other operating expenditure for the network infrastructure, mainly for the control and the maintenance of the system as incentivised.

Implications of the stylized scenario

The described scenario could have significant implications:

- **Large share of cost exempt from incentive regulation** – our below stylized graph (Figure 2) illustrates that only a minor share of transmission related cost may be exposed to incentive regulation; and – more importantly
- **Possible lack of incentives to invest in bottleneck capacity** – the mechanism of investment budgets allows recovery of capital cost. Whether any investment takes place will depend
  - firstly, on whether the rate-of-return allowed by the regulator covers the "true" weighted average cost of capital (WACC) of the network operator; and
  - secondly, on wider incentives - Even if the first condition were met it is, however, not clear that investment would be steered in an efficient manner, e.g. to remove network congestion. In particular, and as we saw based on our stylized example above, it would be optimal for the network operator to consider the trade-off between the cost of network investment and the saving in congestion cost (which is largely the saving in power generation cost thanks to a cheaper plant dispatch). However, in the proposed regime, the network operator would not have an incentive to consider this trade off: capital and congestion cost are of a pass-through nature and he would not draw a commercial benefit by investing in the relief of congestion.

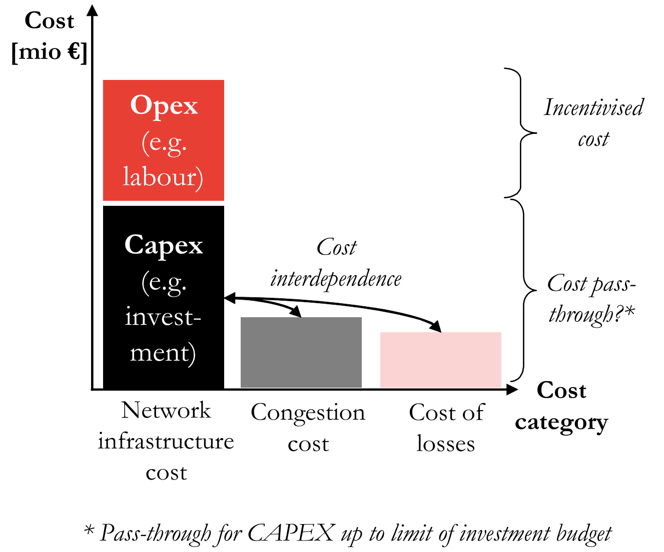

Figure 2: Possible treatment of transmission related costs in Germany (schematic)

To be clear – we would not suggest that German network operators would renege on their commitment to invest in the network. The point we raise is

- whether the new regulator provides incentives to invest in the right amount of capacity in the right location at the right point in time; and
- whether the regime provides the right incentives to trade off "soft" (operational) measures against "hard" (investment) measures in order to enhance network capability.

If such incentives were not in place then the motivation for investment would largely be political pressures. Such a scenario would however contradict the logic for a move to incentive regulation for transmission system operators.

4. INVESTMENT INCENTIVES IN OTHER JURISDICTION

Incentives for network investment and the relief of network congestion have been handled in a more focused manner in other jurisdictions. We discuss three alternative incentive regimes:

- UK: global incentives – in this model as applied in the UK the TSO is also made responsible for other operational cost elements and by reducing these he can make financial gains. Analytical reasoning and practice shows that this enhances efficient investments.
- France/Italy: increased returns on "priority projects" – this approach as applied in the Italian and French gas industries has helped foster dedicated investment projects.
- US/PJM: Merchant or merchant like rewards for investors in a market with zonal or nodal energy prices – this is an approach adopted in some US regions, e.g. the PJM market.

The UK model

The UK incentive scheme for electricity transmission, applied in some form since the mid 1990s, but modified in 2001 following changes to the wholesale market arrangements has the following features:

- **Incentive payments** – the network operator (National Grid) receives/makes incentive payments if he out/under performs against targets of purchase cost of ancillary services. These services include redispatch, i.e. the cost of congestion. The target cost are reviewed and reset periodically (typically every year) – the operating experience of the previous year is used to reset target costs.
- **Capital budgets** – capital costs can be passed through into network tariffs up to the limit of a budget agreed with the regulator.
- **Sliding scale** – the benefits of any out-performance in relation to ancillary services costs are shared between the network operator and network users. In

fact, the network operator can retain 50% of any savings against the cost target. The other 50% have to be passed through into lower network tariffs (Figure 4).

- **Collar** – there is an absolute limit to the absolute amount of incentive payments that may be made in any year. In the UK the possible maximum variation of incentive payments has varied between GBP 60 – 100 Mio/a.

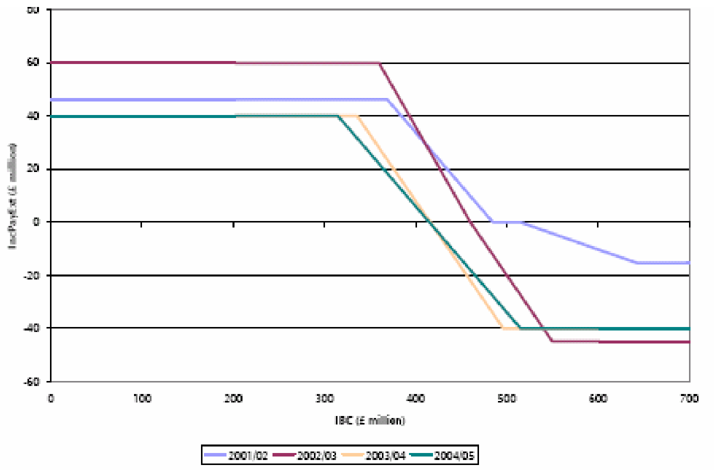

Figure 3: UK Transmission Incentive Scheme

Source: Ofgem

The scheme has helped to significantly reduce the ancillary services cost – and thereby also congestion cost. At the start of the original scheme, congestion costs were around GBP 225m, and reduced over five years to around GBP 30m. Even under the modified scheme post 2001, the savings initially exceeded GBP 100 Mio/a, but reduced over time as the efficiency potential was gradually exploited through new investment (Figure 4).

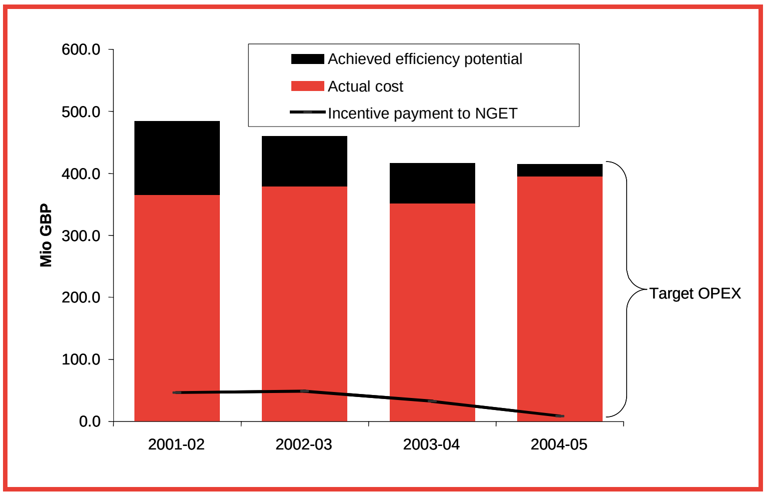

Figure 4: Performance of UK Transmission Incentive Scheme

These reductions could be considered to come from two sources:

- improvements in the efficiency with which NG procures ancillary services (e.g. improvements in contracting strategy, more competitive tendering etc.); and
- improvements in the capability of the network resulting in lower redispatch costs (though the trade-off between opex and capex may be distorted by the short term nature of the incentive scheme – the regulator is considering lengthening the time period between reviews of the cost targets).

The scheme has therefore certainly been effective. We consider the efficiency of the scheme in comparison to the other schemes later on.

The French and Italian model

Regulators in France and Italy have applied a scheme to gas network operators whereby they grant them a preferential rate of return on certain investment projects which the companies and the regulator agree to be strategic. We illustrate the logic here based on the Italian example.

Under Resolution 166/05 of July 2005 the Italian regulator, AEEG, can allow additional returns for individually specified investment projects into gas transport networks. The additional returns are (pre tax):

- +1% for a maximum of 5 years for investment that enhances operating security;
- +2% for a maximum of 10 years for investment that enhances gas transport capacity;
- +3% for a maximum of 10 years for investment within the grid that indirectly enhances gas import capacity; and
- +3% for a maximum of 15 years for investment at import points that directly enhances gas import capacity.

In addition, investment can be promoted by exempting investors from third party access regulations or by allowing them preferential grid access (Laws 273/2002 and 239/2004).

The Italian regime appears to be effective. Its introduction was followed by significant investment in bottleneck capacity (Figure 5). Some concern exists about the efficiency. In particular it is not clear whether

- projects would not have been undertaken anyway, or
- they could alternatively have been triggered by removing other – e.g. administrative – barriers to investment, or
- operational measures would have been more efficient in order to achieve the enhancement in network capability.

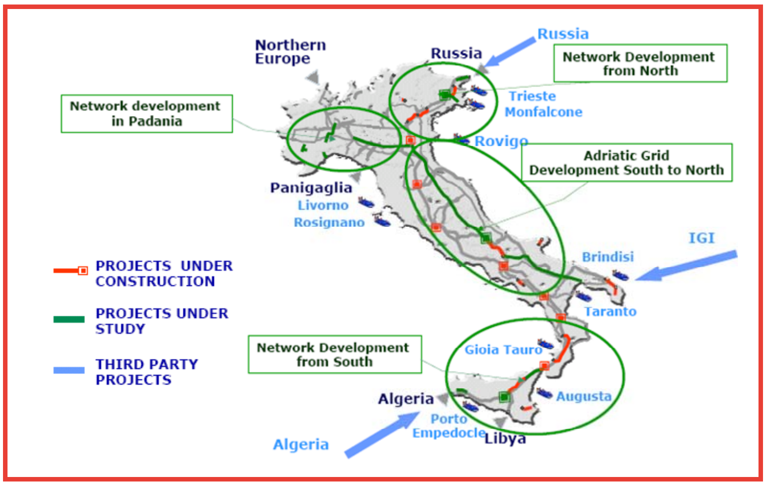

Figure 5: Recent gas transmission projects in Italy

Quelle: SNAM Rete 2006

The PJM model

The logic in the Pennsylvania-New Jersey-Maryland (PJM) market is as follows:

- Energy price differences between network nodes signal investment need- PJM operates a power pool that extends across 14 US states. The market operator, PJM clears the energy auction market taking into account network constraints. In case of network congestion, differences in energy prices between nodes will arise.

- Merchant investors receive financial transmission rights (FTRs) that reflect the market value of the capacity they have built - PJM will hand out financial transmission rights to investors that connect new capacity to the system. These rights entitle the holder to a payment according to the network capacity multiplied by the energy price spread between the connected nodes.

- Receiving **FTR should serve as an investment incentive** for merchant investors - therefore any investor can expect a revenue stream according to the short term value of network connections.

In theory, this regime should lead to efficient investment. In a world of perfect foresight merchant investors would construct new lines up to a point where the marginal cost of investment equals the NPV of the marginal saving of congestion cost (i.e. the marginal energy price spread between nodes).

While the "merchant approach" has clear theoretical merits its practical effectiveness is less clear. The annual market report of PJM indicates that price spreads on grid key connections have increased, suggesting that congestion has increased rather than reduced over the years. At least this suggests that potential investors in transmission have not effectively predicted where shortages in capacity might occur. The increase in price spreads from 2003 may, however, have triggered investment projects which are yet to come to fruition – indeed, it is possible to observe an increase in investment from 2005.

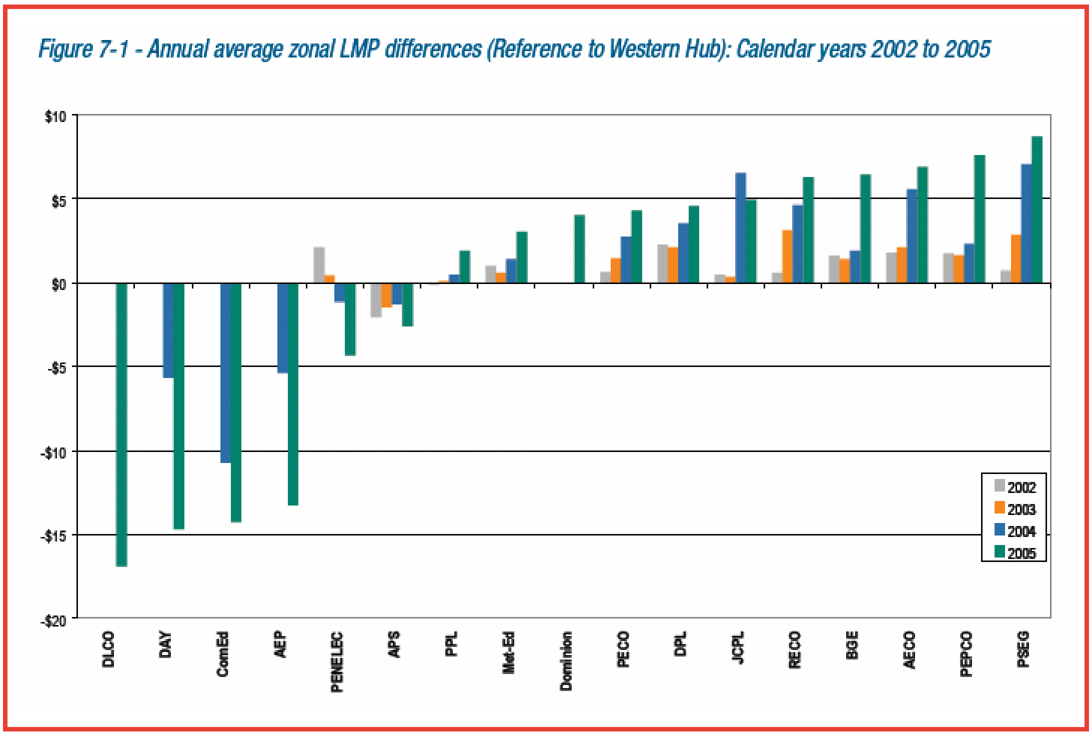

Figure 6: Nodal price differences in the PJM market

Source PJM State of the Market Report 2005

Possible causes for the lack of investment seen to date are:

- investment signals are set through volatile and short term prices rather than through long term signals;
- unclear responsibilities and incentives for system operator, PJM, which may create uncertainties for investors; and
- investments are typically large and non-divisible which means that investors face the risk of derating the congestion rent with their investments. In some cases minimum investment scale may be too large to make it privately profitable, even though it may be socially desirable.[1]

For Europe, arguably a more important issue is that the PJM model does not fit well with EU regulatory and market design approaches, in that it relies on a central dispatch process to calculate nodal prices. We therefore now focus on the other two approaches.

5. PERFORMANCE OF INCENTIVE REGIMES

We now summarise our findings regarding the effectiveness and the efficiency of the explored approaches.

Our analysis so far suggests that we would expect all three approaches (UK, I/F and PJM) to be effective in theory. We now consider the efficiency of those regimes consistent with European regulatory and market designs.

[1] This dichotomy in the private and social assessment may arise as the private investor cares about the return he earns after the investment (the status quo does not feature in this calculation), while the social optimiser also cares about the efficiency gains relative to the situation without the investment.

It is difficult to draw a direct empirical efficiency comparison and we therefore resort to analytical considerations. Based on these we consider that the UK approach has been more efficient although concerns exist with both approaches.

- **Global incentives combined with a sliding scale and collars to contain risk (UK)** – significant attention has to be paid to containing the risks which the network operator himself cannot control. Instruments used include a profit/loss sharing mechanism (the "sliding scale"), collars that limit the incentive payment and thereby the risk exposure and an annual review of target cost of the ancillary services procured by the network operator. In particular, questions arise whether an annually moving target provides sufficient long term incentives for investment. The empirical evidence so far (only) suggests that it has been effective. The UK regime also induces the network operator to trade off the cost of investment against the cost of "soft" measure to enhance network capability.
- **Project specific additional return (I/F)** – under this scheme the regulator does not address the issue of a disjoint optimisation of congestion and network infrastructure cost. Rather, the regulator decides on priority projects which are then allowed a higher return. This may give rise to regulatory failure (approval of inefficient investment) or windfall gains and redistribution (in cases where investments may have been undertaken even without the additional return). This measure is more applicable to structural bottlenecks that can be clearly located and less suitable for congestion in meshed networks. The Italian and French regime does <u>not</u> induce the network operator to trade off the cost of investment against the cost of "soft" measure to enhance network capability.

The following table summarises our considerations:

	UK (electricity)	Italy, France (Gas)	US (PJM)
Model	Global incentives	Special treatment of „strategic projects“	Merchant investment
Incentive lever	Congestion and loss cost incentivised	Increased ROCE on „strategic projects“	Competition from private investors (Nodal pricing signals the value of network investment)
Risk back stop	Cap on value at risk Risk sharing through sliding scale	No down-side risk for investor	
Issues (is it efficient?)	Incentive scheme revised on annual basis gives no long term signals	Incentives through above market return rather than conside-ration of congestion cost Windfall gains (?)	Short term signals Indivisibility of investments

Table 2: Comparison of alternative incentive regimes

6. CONCLUSION

We conclude by summarizing our finding and pointing out a number practical challenges in implementing an improved incentive regime. We point out some possible, though not perfect, solution and consider whether they could also be implemented in the German institutional environment.

Practical challenges

We have so far identified the merits of a global incentive regime. The logic of favouring this regime has – in summary – been that the TSO has the ability to control congestion cost through investment. His revenue/return can be linked to the cost of congestion on the system He will undertake desirable investments because he financially considers the trade-off between investment cost and the cost of congestion.

The practical implementation of this regime however poses significant challenges which we consider now. A key challenge is that the cost of congestion are not exclusively determined by the TSO. Other exogenous drivers include e.g.

- customer loads and energy transits;
- plant outages; or
- electricity wholesale prices – the price spread at both ends of a congested line determines the cost of the congestion.

Measures to limit TSO risk

A number of measures could be used to help reduce the risks for the TSO if incentive regulation was extended to include cost elements such as congestion cost:

- **Regular review of target cost** – the incentive scheme would require target values of e.g. congestion cost to be defined. Any departure from target cost would result in a bonus or malus payment. Therefore the definition of a target value will be of critical importance to the financial impact of the scheme. Given the possible volatility of congestion cost between years the scheme may need to be reviewed on a regular – e.g. as in the UK annual basis. The following trade-off needs to be considered: the longer the validity of the target value, the more reliable the incentives but also the greater the risk for the network operator.
- **Caps and collars on the incentive payments** – one of the design elements of the UK regulation has been to cap the level of profits and losses that can be made through the incentive regime for ancillary services cost. It should be noted that the introduction of collars would still make network operators responsible for

exogenous risks. The collars would serve to *limit the absolute risk exposure*, though.

- **Sliding scale mechanism** – under this scheme the benefits and risks of the incentive schemes are shared between network operators and network users. This limits the leverage of the incentive and thereby also *limits the relative effect of risks*. It still makes TSO partly responsible for exogenous risks as in the UK the incentive scheme could be combined with collars.

- **Indexation of incentive scheme against exogenous drivers** – it may be possible to index the scheme (e.g. targets, caps/collars) to exogenous drivers. This could allow reducing different types of risk:

  - Price risk – some of the risk exposure of congestion cost stems from variations in electricity prices and price spreads between the points of congestion. For example, the "congestion cost" measure could be corrected for variations in the price spread, e.g. by assuming a constant cost spread (this would e.g. require knowledge of "congestion volumes" and the definition of a standard cost spread).

  - Volume risks – volume risks could be limited by indexing the incentive scheme to loads, transits or certain plant outages. A key challenge will be defining and weighing and thereby valuing each of these drivers.

- **Adjustment to allowed rate of return** – the described scheme would potentially increase the risk for the network operator (depending on whether the target level of cost is set more or less prudently). This may need to be reflected by adjusting the allowed rate of return.

Considering the appropriate regulatory gearing

It is not only worth considering which regulatory instruments are available but also how they could be geared. It is worth considering two alternative scenarios:

- **Return on investment allowed by the regulator is set prudently** (high) – in this case the network operator may be allowed return which exceeds his actual cost of capital. Where recovery of investment outlay is separately ensured (e.g. because investment budgets are applied) the network operator already has a strong incentive to invest. Further incentives schemes would serve to

  - induce the network operator to consider the trade off between "soft" operational measures and incentives to enhance network capability; and

  - steer investments into areas which are most beneficial to the market (e.g. by removing/avoiding congestion).

  In this instance a low incentive gearing (e.g. low cap on incentive payment and low profit sharing factor) may be sufficient to achieve the desired effect.

- **Return on investment allowed by the regulator is set restrictively** (low) – in this scenario there is a risk that the allowed return is insufficient to allow the network operator to recover his CAPEX. In this scenario the additional incentive payments may help to make socially desirable investments financially viable for the network operator. The regulator has to be careful through, not to create new risks for the network operators which further increase the cost of capital, thereby making investments even less attractive. The regulation could e.g. be designed asymmetrically, creating a larger upside opportunity than downside risk for the network operator (see e.g. the UK scheme in some years).

Institutional challenges in Germany

We see two options to reflect an incentive regime in Germany if this was politically desired:

- With **amendment to the proposed incentive regulation Decree** – it may make sense to refine the regulation formula to include congestion cost as (partly) controllable cost but to clearly limit the risks to network operators;

- **Within the current Decree** – as we expect the incentive regulation decree to be passed imminently, stakeholders in Germany may need to operate within the given rules. This may limit the possibilities of designing an effective and efficient regime. A certain degree of freedom may still exist by appropriately specifying the – as yet vaguely formulated - quality regulation. Specifying an effective regime within the limits of the Decree is likely to pose a significant challenge, though.