Introduction
The DTc may receive propositions from private entities to build a cross-border interconnection between the UK (strictly England) and the Netherlands (UKNLI). Based on the Dutch Electricity Act 1998, the director of the DTc should authorise such a cross border link, and see to it that the interconnector is utilised in an ‘economically sound fashion’. Also, third parties must have access to such capacity and the link should have a positive effect on trade between countries. These general requirements that leave significant room for interpretation have led the DTc to ask the Market Surveillance Committee (MSC) to examine the possible (adverse) effects of an interconnector on Dutch welfare.

The aim of this MSC paper is to analyse the (potential) effects of an interconnector between the UK and the Netherlands (hereafter UKNLI) and what regulatory measures might be taken to mitigate any adverse effects caused by such a UKNLI. Examples of adverse effects are issues surrounding market power caused by controlling power flows over the link. Market power is a relevant issue since the construction of a link between the Dutch power market and the UK market will likely have an impact on the Dutch market structure. A DC link with 1,000 MW capacity seems material when compared to the installed capacity of the major generators, and to AC import capacity with Germany and Belgium. Peak electricity demand in the Netherlands is of the order of 14,000 MW and AC import capacity is 3,600 MW - due to increase by some 1,000 MW during 2003. It is therefore likely that the interconnector capacity will have an effect on electricity prices in the Netherlands. Other issues such as security of supply may have an adverse effect on social welfare since, in contrast to a new power plant, an interconnector may cause a sudden change in effective net load equal to twice its capacity when the price difference between the two interconnector regions suddenly reverses. On the other hand, the interconnector can be considered as a price-responsive generator and/or load, so although the Netherlands could suddenly experience a swing in effective demand of 2,000 MW (if she had previously been importing), this would only happen if prices in the UK were higher than in the Netherlands. The main problem would seem to be that prices on the UKPX might be allowed to rise above the price cap on the APX of 1,600 Euros/MWh, and the interconnector could not then be used for balancing Dutch supply and demand.

The remainder of this paper is organised as follows. First some background issues are discussed concerning merchant cross-border interconnections. Then the value of a UKNLI merchant interconnection marginal profitability is calculated. This will also shed light on the

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1 Scotland at present operates under different trading arrangements than England and Wales, and Northern Ireland is only weakly connected to Scotland. The link would connect to the grid of England and Wales, in England.
profits of the interconnector. The next section will focus on the impact of an interconnector on prices and includes market power issues. The section that follows will present an analysis of different regulatory measures that may be imposed by the director of the DTe. The document then invites responses to a set of questions posed for consultation.

**Background**

The transmission system on the European mainland consists of national grids, operated by national transmission system operators, which are public or private monopolies. These national grids are integrated into a European system by numerous interconnections, which facilitate both mutual assistance between neighbouring system operators, and to an increasing extent, trade between previously separated electricity markets.

In addition, when the electric power industry was made up of regulated vertically integrated monopolies, decisions about investments in generation and transmission and associated locational decisions were typically made jointly by the same firm, arguably internalising these interdependencies. Accordingly, in restructured electricity sectors where generation and transmission investment decisions are made independently and power prices deregulated, some governance framework must be found to facilitate efficient co-ordination of (generation and) transmission investments and to account for the short run and long run social costs of congestion, changes in reliability and market power.

In the past, building and operating (cross-border) interconnectors was the domain of mainly publicly owned system operators. New proposals by the Council of the European Union for the regulation of cross-border exchanges open the possibility for private initiatives in investment in cross-border interconnection.

To evaluate the properties of alternative transmission investment frameworks with private investors one should be precise about the organisation of the wholesale market, congestion management and price determination to understand and evaluate alternative institutional frameworks to govern transmission investment. Here lies the difficulty of drafting the precise criteria for a regulatory framework, since at present no single paradigm exists for these attributes of the design and operation of wholesale markets, system operations, and congestion management.

In the US and in Australia regulators already have some experience with merchant power lines. For instance FERC’s Standard Market Design interconnectors are seen as assets providing linkage between separated markets. In this model the boundary between infrastructure and market parties is shifted: a line is drawn between a regulated regime for national transmission systems and a deregulated regime for market parties, including interconnectors. Interconnectors are treated as a power unit in one country and a load in the other. Therefore they are treated as “merchant” and subject to minimal regulation. Price spreads between regions trigger investment by competing firms and provide return to investors. The costs of these merchant investments are not to be recovered through regulated tariffs. The job of the regulator is to set requirements for transparency and non-discriminatory allocation, as well as methods to restrict the abuse of market power.
**Proposed procedure**

Standard practice would be to issue a consultation document on the proposed regulation of any UKNL interconnector, setting out DTe’s arguments for the proposed form of regulation, and inviting comments from interested parties. These comments would inform the final publication of proposed regulations.

An important question to address in this consultation is whether, as DTe is minded, provision should be that after a certain number of years (to be determined in the consultation process) DTe would have the option of requiring that the UKNLI become subject to the same regulations as any other interconnector. Provisionally this date might be set 10 years after commissioning. The reason for this option is that it should involve little cost to the investors of the interconnector, but it provides assurance to the market and consumers that any potentially adverse effects that might arise from the asymmetric treatment of this and other (necessarily regulated) pre-existing interconnectors can be addressed without calling into question the good faith under which the interconnector was originally authorised.

**Markets**

Installed generation and total consumption are respectively 3.5 and 3 times larger in Britain than in the Netherlands (see figure 1). In addition, competition in the wholesale electricity market is more intense in England and Wales. One of the main reasons for the more competitive wholesale market in England and Wales has been the extensive divestiture of plant by the incumbent generators, although Ofgem claims that the New Electricity Trading Arrangements (NETA) also contributed to increasing the intensity of competition. The NETA replaced the previous gross Electricity Pool in March 2001 by a series of wholesale markets (bilateral, OTC, and day-ahead) and a new Balancing Mechanism. Due to the size of the UK market (i.e. generation and consumption) compared to the Dutch market and the results from NETA it seems unlikely that a interconnector between the UK and the Netherlands will have a material effect on British wholesale electricity prices in the short run. The impact of the interconnector on Dutch electricity prices will be discussed later in the paper.

![Figure 1. Installed capacity and consumption in the UK and the Netherlands, 2001](source: Prospex, 2002)
Revenue
A UKNLI offers the opportunity to transport power from the lower price region to the higher price one. Its economic (arbitrage) value per MW is therefore, at any given hour, equal to the absolute price difference (the market spread) between the regions,

\[ v(t) = |p_1(t) - p_2(t)|. \]

While in some circumstances it may be the case that power flows are always in the same direction, i.e. one region is always lower priced, in general this will not be true. In figure 2 below we plot, as an example, the current situation for the UK - Dutch markets (for hours of Continental time), where in general the British market is lower priced.

**Figure 2  Average hourly UKPX and APX prices, 2002 (Euro/MWh)**

![Average hourly UKPX and APX prices, 2002 (Euro/MWh)](image)

*Source: APX; UKPX, FT*

The low prices prevailing in the Netherlands during the night means that it is profitable to export during off-peak hours, and import during peak hours.

The total ex-post annual value of an interconnector will be determined by the sum of the economic value over the year,\(^2\) multiplied by the available capacity, \(K\):

\[ V = K \cdot \int v(t) \, dt. \]

Electricity markets typically exhibit a large degree of price volatility, caused by random fluctuations in both demand (due to e.g. changing weather conditions) and supply (planned and unplanned outages of generation equipment, outages or maintenance on other transmission lines). Connecting markets with uncorrelated price fluctuations (see figure 3

\(^2\) Ideally, if prices can be forecast for the life of the interconnector, the present discounted value can be computed, in which case the hourly values should be discounted back to the present.
below) enables an investor to capture the volatile component of price spread, even if in expectation prices are equal.

**Figure 3. Scatter diagram of noon UKPX and APX prices in Euro/MWh, June 2001 – February 2003**

Source: APX, UKPX and FT.

Using hourly data for the UKPX and APX and assuming that trade can reverse every hour and that import into the Dutch market has no effect on the prices, it is possible to compute the profitability of the right to import or export 1 MW in the profitable direction every hour. Figure 4 below shows the *quarterly profit* per MW for each hour of the day for just exporting or just importing. As figure 2 shows, it is profitable to export during the off-peak hours, and to import during the peak hours, and it typically is more profitable to import.

**Figure 4. Hourly revenue from trade in both directions per quarter per hour, 2002**

Source: APX, UKPX.

Annual revenue is 126,350 Euro/MW/year. The figure shows that in particular the third quarter revenues are relative high. Figure 5 below plots the monthly revenues during peak and off-peak hours in 2002. The figures reflect to some extent the high prices during summer.
months, which are probably due to the relative warm summer days when demand in the Netherlands is relatively high (partly due to the demand for air-conditioning) and supply is lower (partly due to cooling water restrictions). However, temperature is not the only driver, since the October revenues appear relatively high also.

![Figure 5. Revenue per MW of interconnector capacity per month, 2002](image)

**Source:** APX, UKPX.

**Costs**

Undersea DC interconnector construction not only involves laying a cable (using technologies that were developed mainly for the off-shore oil industry) but also the construction of converter stations at both ends, and connection to the on-shore high-tension grid. Typically investment in such projects has some degree of lumpiness, not only due to the actual laying of the cable, but also because the costs of the various electrical components do not scale with capacity.

![Figure 6. Economies of scale in transmission infrastructure](image)

**Source:** Brunekreeft (2003).

There seems to be consensus that transmission capacity has economies of scale. The above figure 6 shows economies of scale based on real construction costs for above ground DC interconnectors, though excluding right-of-way costs, that is the cost of land and the legal right to use and service the land on which the transmission line would be located. The figure plots average costs (Euro per MW per mile) in relation to the line’s capacity, as the least-cost
envelope of different technologies. It appears that DC interconnectors are used for bulk power transactions. As a result the scale economies may be exhausted at some point; the above figure suggests that beyond 750 MW long run marginal costs are nearly constant.

Industry estimates for the costs of a 200 km long bipolar HVDC cable link at 1,200 MW capacity rating, including converters, are in the order of EUR 350 million. The cost effect of a 200 MW increase or decrease (+/-17% in capacity) would only typically involve circa +/- 5% change in cost.

Unfortunately we lack a comparable range of cost estimates for different DC undersea links. However, if economies of scale also appear for DC undersea links, such as the UKNLI, regulation may be needed prior to construction in order to avoid underinvestment. Economies of scale imply that it would be more costly to provide the same capacity in two or more separate interconnectors, and allow the investors to pre-empt future interconnectors by raising their unit capacity costs, and discouraging the provision of further capacity. One standard solution is to require that the investors allow those who wish future access to capacity to join the consortium and co-finance the project (effectively through contracts for use). If all potential demands can be aggregated and no users are denied access to this capacity allocation process, then concerns over restricting capacity to increase market power should be alleviated.

ETSU’s *Concept study – Western Offshore Transmission Grid* gives rough estimates of DC undersea links. For a 100-500 MW HVDC transmission scheme based on a voltage source converter, the costs are 25 million Euros/100MW for the converter equipment (almost constant returns to scale) plus 720,000Euro/km for cable. If the link is 150 km, then the cable cost alone would be 130 million euros (allowing for a 20% contingency). The total cost would be 160 million euros for 100 MW (= 1.6 M euros/MW) and 280 M euros for 500 MW (= 0.6 M euros/MW).

The same source considers larger links based on a hybrid converter, where for a 2,000 MW link the converter costs are 540 M euros and the link is 1.6 M euros/km, giving the total cost as 860 M euros (with a 10% contingency, or 0.43 M Euros/MW). The economics of a larger link are probably comparable to the intermediate size, as the lower cost per MW is secured only with a larger potential impact on the price difference.

**Profits**

Table 1 below gives the arbitrage profits for various 12-month periods at current (2001-3) prices and adjusting them as described below for possible future price scenarios. At current prices, if the interconnector is small (e.g. 100 MW) so that prices are unaffected, then the annual returns average between 0.11 M Euros/MW/yr to 0.14 M Euro/MW/yr, compared to an investment cost of 1.6 M Euro/MW, or a return of 7-9%, which is sub-marginal. The return to a 500 MW link costing 0.6 M Euros/MW would be 18-23%, assuming no impact on prices.³

For a larger interconnector (1.5-2 GW) costing 0.43 M Euros/MW prices may well be affected. If the size is such that half the price difference is preserved indefinitely, so that the

³ Estimates exclude costs for maintenance and assume 100% availability.
annual returns per MW fall to between 0.06-0.07 M Euros/MW, the returns lie in the range 13-16%. The economics of the UKNLI thus depend on its size and its impact on price differences (and the nature and size of those price differences, as we shall see below).

In 2001-3, prices in Britain were below those in the Netherlands, and hence imports into the Netherlands would be profitable on average and imports into the Netherlands would be more common than exports to Britain. In the medium run this cannot be guaranteed, as both countries increasingly converge on gas-fired generation and adjust capacity to suit demand. Given that gas prices are likely to converge, it is reasonable to expect that average electricity prices will also converge and the present situation will no longer prevail. Nevertheless, the profitability of the link depends not so much on the average difference in price as the difference in price in any hour, which may continue to be as high or higher than before. The reason is that the dynamics of prices over the twenty-four hours differs in the two countries given the characteristics of plant and the load profiles, as typically Dutch prices are below British prices off-peak even at the moment, while British prices are below Dutch prices at the peak.

To investigate the effect of changes in average prices on the profitability of the link, British spot prices have been adjusted by the formula $p^* = p^0 + b(p-p_0)^3$, where $p$ is the current spot price in Britain, and $p^*$ is the adjusted price, as shown in figure 7. A value of $p_0$ of 10 euros

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4 This adjustment assumes that the British spot market will become tighter as demand expands and/or plant is disconnected, so that the average UKPX price is the same over the year as the APX price. The formula attempts to capture the more intense competition in low price hours when capacity is abundant, and the increasing mark-up on marginal costs as capacity becomes tighter and prices rise. It
MWh and 0.0125 for the value of $b$ gives the same average prices in the two countries, but increases the peak hour prices in Britain to reflect increasing scarcity of supply as capacity and demand come more into alignment. The effects on the profitability of a proposed interconnector are interesting and suggest an increase in returns of 10 per cent or more, as table 1 below shows. This suggests that the major profitability of the interconnector lies in its ability to arbitrage volatile and imperfectly correlated prices in the two countries.

### Table 1. Total revenue per MW of interconnector capacity per year, Euro/MW/year

<table>
<thead>
<tr>
<th></th>
<th>Original</th>
<th>Adjusted</th>
<th>Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>June 2001-2002</td>
<td>124,007</td>
<td>142,547</td>
<td>1.15</td>
</tr>
<tr>
<td>July 2001-2002</td>
<td>126,996</td>
<td>144,280</td>
<td>1.14</td>
</tr>
<tr>
<td>August 2001-2002</td>
<td>109,465</td>
<td>125,493</td>
<td>1.15</td>
</tr>
<tr>
<td>September 2001-2002</td>
<td>116,453</td>
<td>130,616</td>
<td>1.12</td>
</tr>
<tr>
<td>October 2001-2002</td>
<td>120,142</td>
<td>132,769</td>
<td>1.11</td>
</tr>
<tr>
<td>November 2001-2002</td>
<td>132,932</td>
<td>145,854</td>
<td>1.10</td>
</tr>
<tr>
<td>December 2001-2002</td>
<td>137,423</td>
<td>153,300</td>
<td>1.12</td>
</tr>
<tr>
<td>January 2002-2003</td>
<td>126,341</td>
<td>143,976</td>
<td>1.14</td>
</tr>
<tr>
<td>February 2002-2003</td>
<td>139,614</td>
<td>154,613</td>
<td>1.11</td>
</tr>
<tr>
<td>March 2002-2003</td>
<td>142,832</td>
<td>156,613</td>
<td>1.10</td>
</tr>
</tbody>
</table>

*Source: APX, UKPX and MSC calculations*

### Price effect of the interconnector on the Dutch prices

It is easiest to compute the profitability of the UKNLI on the assumption that the interconnector has no effect on price levels. Though this may be realistic for the UK market, since the UK market, in the short run, is sufficiently large compared to the link capacity, it seems unlikely that a 1,200 MW interconnector has no, or only a negligible effect on Dutch prices. In order to determine the effect of the interconnector in the Dutch market we have run several simulations.

First we have simulated the effect on average marginal costs when load is decreased by 500 and 1,000 MW, respectively, resulting in base load average marginal cost decreases of 1.5 and 2.8 Euro (see table 2).

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is intended as a rough and ready sensitivity test of the influence of future market developments, and is not to be taken as a reliable forecast of future UK prices. It does, however, address the fact that the current daily price profile is very muted compared to earlier periods, reflecting a possibly temporary excess of spare capacity. The results are fairly insensitive to changing $p_o$ to values up to 15 Euros/MWh.
Table 2. Marginal simulated value of underlying generation costs in different load cases for the Dutch market (Powrsym3 results)

<table>
<thead>
<tr>
<th>Load a)</th>
<th>Base case</th>
<th>500 case</th>
<th>1000 case</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Average MC Load -500</td>
<td>Euro diff.</td>
<td>Load -1000</td>
</tr>
<tr>
<td>Base load</td>
<td>7,597</td>
<td>28.7</td>
<td>7,097</td>
</tr>
<tr>
<td>Noon</td>
<td>9,231</td>
<td>35.2</td>
<td>8,731</td>
</tr>
<tr>
<td>Peak load</td>
<td>8,449</td>
<td>32.2</td>
<td>7,949</td>
</tr>
<tr>
<td>Off-peak load</td>
<td>5,674</td>
<td>20.6</td>
<td>5,174</td>
</tr>
</tbody>
</table>

Source: MSC calculations.

The result, 1.5 Euro (base load) is relatively small. However, this analysis has some important drawbacks. First it does not include the effect of competition itself and, second, it does not capture the volatility of prices between hours and exchange rate fluctuations. Hence, average marginal costs seem a rather rough measure for the impact of an interconnector on prices and it probably underestimates the effects we are interested in. We will return to this issues below using another approach.

Market power

To further assess the impact of the UKNLI on Dutch electricity prices analysis of concentration indices and a Cournot simulation model (that calculates market outcomes assuming strategic behaviour) have been performed. Clearly the extent to which market power is affected by the UKNLI depends on who controls the import flows from the interconnector. A merchant interconnection investor with a large presence in the Dutch power market will have different incentives regarding the prices at which extra capacity will be offered to the market than a new entrant to the market. Therefore we will, in the next section, assess the effect on market structure using three scenarios:

Scenario 1: The capacity is offered competitively to the market, i.e. at a price related to purchase costs.
Scenario 2: A new strategic player, who controls all new capacity but no other generating capacity, offers the imported electricity to the Dutch market.
Scenario 3: The largest current generator in the Dutch market has full control over imports and uses these strategically.

The first scenario effectively means that new imports will add to the competitive production fringe, increasing the elasticity of the residual demand for incumbent strategic firms. In the second scenario the new entrant becomes a new strategic player similar to (though slightly smaller than) the current major generators. The third scenario will be a ‘worst case’ scenario in terms of increase of market power and effect on prices.

Market concentration

The current Dutch generation market consists of in total some 20,000 MW of production capacity. In addition, import capacity from Belgium and Germany amounting to a maximum of 3,350 MW is currently available to the market (expected to increase to 4,350 MW during 2003). Of the 20,000 MW capacity, a large part consists of ‘decentralised’, embedded capacity, local (mainly CHP) plants operated by industrial and horticultural users, partly to cater for their individual power and heat demand. Part of this capacity also participates on the power market, but it is often not clear who has operating control over this capacity. Some of
this capacity is being held in the portfolios of supply firms. In the following analysis, only larger units (>60 MW) are taken into account (plus some central smaller units operated by larger producers). The effect of market participation of the smaller units may be represented by a larger (residual) demand elasticity than would be accounted for by consumption only.

The total capacity accounted for by the larger units is some 15.7 GW, including some units that are currently mothballed but could be put into operation at short notice. Four large players operate most of these units: Electrabel, Essent, E.On and Reliant. Reliant is in the process of selling its Dutch production units to Nuon, a large distributor, and the fifth, currently smaller, generator.

We may measure market share for this set of units based on installed capacity. This does not necessarily reflect market shares in terms of output. At peak demand, when market power may be most serious, the interconnectors with Germany and (to a lesser extent) Belgium are usually congested, which means that an additional 3,350 MW is fed into the system. We include this in the market share analysis.

Apart from market shares, a second measure of market concentration that is frequently used is the Herfindahl-Hirschman index (HHI), the sum of squared market shares. The HHI can be roughly described as relating the level of competition to a market that is divided among 1/HHI equal players. A HHI of 0.2 corresponds to a market with 5 equal players, and a HHI of 0.15 would indicate a level of competition between that in a market with 6 equal players and one with 5.\(^5\)

In table 3 we list the current market shares and resulting HHI for the market restricted to central units. The imported power may be partly under control of the incumbent players (subject to a cap of 400 MW), so that these figures are lower bounds.

We can now investigate the effects on market concentration caused by construction of an additional 1,500 MW of import capacity, under the three scenarios of control over imported power (competitive, new strategic player, largest incumbent). In the competitive scenario, we

\(^5\) The US approach is to measure shares as percentages, in which case the HHI is 10,000 times as large, so the five-firm equivalent would have a US HHI of 2,000.
allocate the market share to “Other”. The resulting market shares and HHIs are given in table 4.

**Table 4: market shares and HHI after construction of new capacity**

<table>
<thead>
<tr>
<th>Player</th>
<th>Scenario 1: competitive new player</th>
<th>Scenario 2: new player</th>
<th>Scenario 3: Largest incumbent</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electrabel</td>
<td>24%</td>
<td>24%</td>
<td>31%</td>
</tr>
<tr>
<td>Essent</td>
<td>20%</td>
<td>20%</td>
<td>20%</td>
</tr>
<tr>
<td>Reliant</td>
<td>17%</td>
<td>17%</td>
<td>17%</td>
</tr>
<tr>
<td>Eon</td>
<td>9%</td>
<td>9%</td>
<td>9%</td>
</tr>
<tr>
<td>Other</td>
<td>13%</td>
<td>6%</td>
<td>6%</td>
</tr>
<tr>
<td>Imports</td>
<td>16%</td>
<td>16%</td>
<td>16%</td>
</tr>
<tr>
<td>New player</td>
<td>7%</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>100%</td>
<td>100%</td>
<td>100%</td>
</tr>
<tr>
<td>HHI</td>
<td>0.135</td>
<td>0.140</td>
<td>0.175</td>
</tr>
</tbody>
</table>

*Source:* MSC calculations.

*Note:* In this table it is assumed that the prices for the electricity imported (1,500 MW) are always lower than market prices in the Netherlands and that the interconnector is fully used.

The effect on the HHI of giving control to the largest incumbent, compared to the competitive scenario, is therefore to the increase the value by (approx.) 0.04.

**Strategic behaviour**

The model includes a number of generators owning a generating park consisting of units with different capacities and marginal costs. These generate power to meet an exogenous demand, which is price sensitive. We assume that power demand can be described by a constant-elasticity demand curve. In our approximation of the Dutch system, we use the capacity and approximate marginal cost data of the four large generators, and treat these as Cournot players, making output choices so as to optimise their revenues. Their choices are contingent on the residual demand function they face. Residual demand consists of aggregate demand less demand served by generation units owned by other operators and imports. We treat these contributions as price taking: capacity from these sources is offered to the market whenever the market price is higher than marginal costs.

Total demand is understood to exclude demand served by small, embedded generation. The presence of these production facilities can be accounted for by increasing the elasticity of demand. Imports, in the base case before construction of a DC line, are estimated at 3,000 MW, assuming that the Belgian interconnection is not fully used. Cost price for import ranges from EUR 25 to 30; that is, at a price lower than EUR 25 no imports take place, while at prices higher than EUR 30 one has a maximum utilisation of the 3,000 MW.

We successively analyse four cases: a base, or reference, case without new transmission lines, as well as the three scenarios discussed above. We assume that in all cases prices in the source country are EUR 20, so in general below the market outcome in the Netherlands. The analysis is carried out for a demand elasticity of 0.5. This is fairly high if interpreted as the elasticity of end user demand, but is chosen so as to reflect effects of embedded generation.
In Figure 8 above results are plotted for the computations under scenarios 1 to 3 as compared to the base case and the loads that feed-in to the model are sorted in ascending order. Scenario 1 represents competitive, i.e. price taking, additional imports, whenever market prices are above EUR 20. Scenario 2 describes a new entrant who has the power to hold back some of this capacity. Scenario 3 involves the largest player having control over imports. We see that in all scenarios, the system price benefits from the additional capacity. For low load levels, prices drop only marginally, and the allocation of capacity has no significant effect. At higher loads, there remains little difference between competitive use and a newcomer having full control. The reason is that the new capacity is effectively base load capacity (due to the low price assumed for imported power), so that the newcomer benefits most from behaving as a price taker. The third scenario does give markedly different behaviour however. At peak loads, the largest firm's control still pushes prices upward to the base case level, giving less impact on price. The best aspect in this scenario over the base case is that the threshold to the four-player regime occurs at a higher level.

The above demonstrates that there is the potential for exercise of market power by the users of transmission capacity. Market power considerations may prompt the regulator to issue conditions regarding ownership of transmission capacity or transmission contracts. Examples of these are capacity caps: total ownership of transmission capacity by one individual market party may be limited to a cap value. In the Netherlands such a cap is already applied to import capacity on existing interconnectors.

In addition, general conditions for non-discriminatory access, use-it-or-lose-it and transparency (such as disclosure of prices and volumes, as well as identity of players) may have to be set.

An underlying assumption in the above analysis is that the cost price for imported electricity is always lower than Dutch prices. If we would relax this assumption, which is justified since figure 2 shows that during the off peak hours prices in the UK are higher than in the
Netherlands, and again run the simulation (but now for each hour we allow the interconnector to import and export, respectively) we may obtain a more detailed picture of the effect on Dutch prices.

In figure 9 the impact is illustrated of an additional 1,500MW interconnector capacity that is exploited by a fringe player who arbitrages the Dutch and British market. The prices in the base case are similar to the base case in figure 8. The chart shows that during peak demand hours Dutch prices will decrease due to British imports. In particular, after 18h00 Dutch prices are decreasing compared to the base scenario. At 18h00 however, UKPX prices reach a high level of 40.7 Euro/MWh. Also, during low levels of demand prices are slightly above the base scenario, which is due to export of the link. The main result is that the interconnector reduces price volatility.

![Figure 9. Simulation result for base scenario and a scenario with hourly arbitrage using UKNLI](image)

Source: MSC simulations.

**Regulatory measure matrix**

The first column of the matrix below lists different regulatory measures the DTe may consider. The second column gives arguments that may favour the various measures. Whether the impact on the social welfare (measured as the sum of producer and consumer surpluses) and the business case (i.e. the profitability of the interconnector) is positive or negative is presented in the last two columns. The effect on social welfare assumes that the regulatory measure has no effect on the size of the interconnector as such. If the profitability of the interconnector is adversely affected by the regulatory measure investors may choose a smaller interconnector. In that case it would be necessary to compare the social welfare of a smaller regulated interconnector with a larger, less tightly regulated interconnector. If the regulation is so onerous as to cause the investors to abandon the project the impact on social welfare will be adverse.

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6 The load supplied to the model is ranked as is done in figure 8. At 18h00 the UKPX price is Euro/MWh 40 and is slightly above the APX price. This explains the small peak in the chart. At that moment it is (more) profitable to export the UK.
Figure 9. Input matrix

<table>
<thead>
<tr>
<th>Regulatory measures</th>
<th>Arguments</th>
<th>Social welfare</th>
<th>Business case</th>
</tr>
</thead>
<tbody>
<tr>
<td>Price regulation</td>
<td>Not required</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Interconnector volume cap</td>
<td>Currently there is a volume cap in place on the German-NLD and Belgium-NLD interconnectors. It would be a matter of consistency to impose the cap also on the UKNLI.</td>
<td>Positive</td>
<td>Not positive</td>
</tr>
<tr>
<td>Netcode obligation</td>
<td>This will increase the volume on the APX. Probably this will also increase the liquidity on the APX and hence increase the reliability of a price index available.</td>
<td>Positive</td>
<td>Not positive</td>
</tr>
<tr>
<td>Limiting the fraction of capacity sold on long vs. short term contract</td>
<td>In order to provide investor assurances there would be a reason to have most of the capacity allocated for long-term contracts. However, from a social point of view having some capacity allocated into the day-ahead market (auction) will be beneficial for other market players and probably also for competition.</td>
<td>Positive</td>
<td>Not positive</td>
</tr>
<tr>
<td>Use-it-or-lose-it</td>
<td>Arguably by consistency with other interconnectors one should impose this condition. Though for the Belgium and German interconnectors this condition only counts for year and month capacity. If this capacity is not used it will automatically become available to the daily auction. For this capacity it is possible to buy capacity but not use it.</td>
<td>Positive</td>
<td>Unclear: this might have a negative effect on the size of the link capacity.</td>
</tr>
<tr>
<td>Maintenance</td>
<td>Clear rules should be imposed on the interconnector operations. It is proposed to apply the same operational regulation as is currently installed for the present TSO interconnectors with Germany and Belgium.</td>
<td>Positive</td>
<td>Not positive</td>
</tr>
<tr>
<td>Time dimension (hour, 15min)</td>
<td>If it will be on 15 minutes basis, then the link might provide depth in the Dutch balancing market. However, further investigation is required to understand if the Dutch regime fits the UK balancing system.</td>
<td>Positive</td>
<td>Not positive</td>
</tr>
</tbody>
</table>

Price regulation

Regulated interconnectors are subject to revenue regulation in that the excess of any auction revenue is transferred to either financing additional interconnection or reducing the charges levied for the remaining network. By definition, a merchant interconnector is not eligible for guaranteed revenue, and so logically should not be subject to revenue regulation. It is also difficult to see how an additional interconnection could increase market power in ways that could be only addressed by a revenue cap (rather than a cap on volumes acquired). It may actually be detrimental to the public benefits of merchant investment to impose caps on revenues. Investment in merchant interconnection is subject to considerable risk - this was in fact one of the conditions for merchant investment as mentioned in the European directive. Investment risk implies that aggregate revenues may fall short of, or exceed, expected revenues. Imposition of a cap on aggregate revenues effectively cuts short potential profits (the up-side), but does not take away potential downside of the project and hence reduces expected profits. The rational response to such caps is for the investor to reduce investment.
(or abandon it altogether) to limit his downside risk. This is not only unfavourable for the investor, but also reduces the social benefits from the new capacity.

**Interconnector volume cap**

The initial position would be that the same rules that currently apply to volumes obtained on existing interconnectors should apply to all new interconnectors, with the possibility that the overall individual cap is perhaps raised to 500 MW or in proportion to the increase in interconnector capacity. Views are invited on whether the cap should remain, and if so at what level. The social benefits are the restraint on market power of importing incumbent generators, and the possible impact on the business case are a potential loss of incumbent importer market power, which will influence the value (and amounts) of long-term contracts on which the interconnector will be financed. This could adversely affect the choice of interconnector size.

**Netcode obligation**

Again, the arguments for bidding all interconnect volume into the APX are valid for the UKNLI. The benefits are the improved liquidity, transparency, and viability of the APX. The cost to the investors will be the modest fees payable on transactions, offset to some extent by a reduction in average fees as trade increases but APX costs increase by less.

**Long vs. short term**

Investment in interconnection capacity entails an exposure to the risk of fluctuations in spot market spread. This risk may be hedged using contracts on both spot markets concerned, but also, and more efficiently, by trading transmission rights. In merchant projects in the US, transmission rights in the form of long-term capacity contracts are commonly allocated through an open process, preceding the actual construction of the line. In this case the constructor effectively sells (part of) his transmission option in advance, transferring the actual construction of the line. This freedom to trade transmission rights of various durations allows efficient allocation of risk, and thereby can lead to less costly investment.

The higher the fraction of the UKNLI sold on long-term contracts, the lower the risk of the income flows to the investors and hence the lower the financing cost, to the benefit of the investors. If they decide as a result to invest in a larger interconnector this will increase social benefits. The higher the fraction of capacity sold in the day-ahead market, the easier it will be for traders and/or new entrants to buy spot and sell to customers, and hence the lower the risks and hence costs of adjusting the profiles of contracts or generation output to suit customers.

In addition, in many European markets, including the Dutch market, market liquidity has been diminishing, partly due to the demise of Enron and subsequent withdrawal from the market of most other American traders, partly due to ongoing consolidation and vertical integration in the sector (see the report of the Dutch Market Surveillance Committee: DTe, 2003). This negatively impacts the availability of sufficient trading volume in the market to allow independent players to enter or remain active in the market. In the Netherlands, this has been a motivation for requiring part of regulated TSO interconnection volumes to be made available on a short-term basis (in hourly day-ahead contracts), and to be traded via the spot market.
market, the APX. Similarly one could require that part of the interconnection capacity be offered in short-term (day-ahead) contracts. This enables more flexible reaction to developments on spot markets, thus potentially increasing liquidity.

It is not obvious what proportion of the UKNLI link should be allocated for short-term contract (day-ahead market). A rough estimate might be calculated by deducting the total volume required to serve a typical Dutch load after deducting two standard contracts, that is base load and peak load. These two contracts are optimised aiming to cover a maximum amount of the total load, as illustrated in figure 10. In the figure the total load is represented by the grey area and the base load and peak load contacts are marked with two boxes (dashed lines). Clearly some of the (super peak) load is not served using only these two (ex ante optimised) contracts, and hence should be served using other sources, for instance the spot market. At 7h00 the load not covered by the two contracts reaches almost 35%. The line linking the diamonds in figure 10 illustrates this.

![Figure 10. Typical load served and hourly under and over served volume as percentage of total hourly load](image)

Source: Tennet, MSC calculations.

Note: Averaged over standard working days (Wednesdays) during first 6 months of 2003.

The flexibility required to serve the super peak load and the load during the off peak may be supplied buying on the spot market, which is about 6.5 percent of the total load.

**Use-it-or-lose-it**

The value to the investors of not being subject to this requirement is that they can withhold capacity to preserve a greater price difference between the two markets in some market configurations. Whether this is profitable will depend on whether the parties holding long-term contracts delegate the power to submit e-programs to a single joint venture in which they hold equity, or whether they each decide on commitment decisions independently. In the former case, or where there is a single contract holder, the non day-ahead capacity will be bid in monopolistically to maximise interconnector profits (possibly allowing for any consequential profit impacts on importing generators or suppliers who are party to the UKNLI
contracts). In the latter case their individual market power will be less, and the number of
hours in which the parties will withhold will be reduced, perhaps to zero. One regulatory
decision might therefore be to prevent collusion in commitment decisions. If DT€e imposes
Use-it-or-lose-it, the parties may be able to circumvent this for some hours of the year by
strategically withdrawing converter capacity for maintenance, declared outages, etc. although
this will presumably be for fewer hours than may be expected in the absence of Use-it-or-
lose-it. The social benefit of Use-it-or-lose-it is that of increased trade and hence increased
total social benefit (to both countries taken together). The investor benefits of not imposing
Use-it-or-lose-it is that the profits of the UKNLI are increased whenever the operators are
able to restrict capacity use, and as a result they may be willing to consider a larger
interconnector. The larger interconnector without Use-it-or-lose-it may yield higher social
benefits that a smaller interconnector with Use-it-or-lose-it. The opening consultation position
is therefore one of Use-it-or-lose-it.

Maintenance
Provisions should be the same as for the current TSO interconnectors.

The costs of reinforcement
The costs of reinforcing the regulated network in the Netherlands to accommodate the
additional flows over the UKNLI might reasonably be charged to the UKNLI, although this
would differ from current practice in charging either generators or load for “deep
interconnection” costs. Arguably, if the DT€e decides that the UKNLI has positive social
value, then it might be reasonable for the cost of such reinforcements to be included in the
regulated network (and hence paid for by current consumers).

Is a link good for the Dutch market (i.e. NLD consumers’ surplus)
In general a welfare optimising central planner with perfect knowledge would base its
capacity choice on a balance between the costs of construction of capacity and benefits of
interconnection. These benefits may include greater security of supply, lower reserve margin
requirements, increased competition and reduction of market power. Generally, the largest
welfare effect however is to be expected from the replacement of expensive generation in the
high cost region by lower cost generation from the low cost region.

Do Dutch consumers benefit from the interconnector? If we ignore Dutch benefits as
shareholders in either or both of the UKNLI and Dutch generators, this depends on the impact
on average Dutch prices and on the security of supply. There are four plausible scenarios:

- NL imports on average from both DE (Germany) and UK - Scenario A
- NL imports from DE and exports to UK – Scenario B
- NL exports to both UK and DE – Scenario C
- NL on average imports and exports the same amount to UK – Scenario D

The three variable fuel costs to consider are coal-fired generation $c_C$, thermal gas-fired
generation, $c_{TG}$, and CCGT generation, $c_{GT}$, assuming reasonably that coal prices are the same
in Germany and the UK, and that gas prices in NL are no higher than the UK after 2006, when
the UK is predicted to become a net importer.
Scenario A: $c_{TG} > c_{GT} > c_C$, and capacity tight in NL, sufficient in UK and DE

Scenario B: $c_{UK} > c_{TG} > c_{GT} > c_{CDE}$, and/or capacity tighter in UK than NL, sufficient in DE. This does not seem very likely unless UK imposes higher carbon taxes than DE.

Scenario C: All countries are short of capacity and all are setting prices at LRMC, and the LRMC of CCGT is less than that of coal, and lower in NL than UK (as it should be after 2006 unless the Dutch gas market is very distorted and/or price discriminating in its exports to UK).

Scenario D: More flexible plant in the UK allows higher off-peak prices than NL, and lower peak prices, so that trade is balanced over the day, with off-peak prices rising in NL and peak prices falling.

In cases A, B and C, Dutch consumers are better off with the interconnector, as it has beneficial or neutral effects on Dutch prices and a beneficial effect on security of supply. In case A Dutch prices are lower and available capacity higher than otherwise, and in case C Dutch prices are the same (constant returns with CCGT) and domestic capacity higher. In case D demand weighted Dutch prices should fall. In case B Dutch prices are higher and security somewhat higher than otherwise. Case B seems unlikely as UK generation is likely to remain more competitive than on the Continent, there is likely to be continued spare capacity for longer than in Germany. On the other hand the accession countries may increase exports to Germany, wind power may increase the average reserve margin, both putting downward pressure on prices. The interconnector to Germany will be constrained with or without the UKNLI, so the critical issue is the likelihood of UK prices being on average higher than in the NL. Uniform EU-wide carbon emission prices would raise the marginal cost of coal-fired generation more than that of thermal gas. If coal then became the marginal supply in the UK and thermal gas is the marginal supply in the NL, then exports to the UK might happen, until new investment in Dutch (or British) CCGT became attractive (presumably moderately soon with higher carbon prices).

If one thinks that the greater risk in the Netherlands is periods of high gas prices and that the UK will remain both more competitive and also with a better mix of fuels and plant type (noting that all gas generation in the UK is CCGT and considerably lower cost than in the NL), then prices in the Dutch market should on average fall as a result of the UKNLI. The later will enhance total welfare in the Netherlands.

**Questions for consultation**

DTe seeks views on the following questions:

1. Should there be an open season in which potential users of the UKNLI are encouraged to bid for long-term capacity in the UKNLI, to ensure that the maximum size of interconnector is built?
2. Should some fraction of the UKNLI be reserved for daily auctions? If so, what should that fraction be?
3. Should there be limits on the amount of capacity that any Dutch generator should be allowed to control, and if so, would it be reasonable to impose a separate limit on the UKNLI (in addition to existing capacity limits) of 25% of the total UKNLI capacity?
4. Should capacity be held under “use-it-or-lose-it” conditions, with the balance made available to the day-ahead auction (or its equivalent)?
5. Should all capacity secured on the UKNLI be traded through the APX as for other interconnectors?
6. Should the UKNLI or TenneT bear the cost of any on-shore grid reinforcements required to support the UKNLI?
7. Should the UKNLI be exploited on a 15 minutes basis (as for the balancing market), an hourly basis (as for the APX), or for some other time unit, and if so, why?
8. Should DTe have the option to take that part of the UKNLI that comes under Dutch jurisdiction into the regulated network after 10 years, and thereafter to pay a regulated revenue equal to operating costs plus the return on and depreciation of the depreciated value of the interconnector?

Conclusion
The UKNLI is a proposed merchant interconnector where the investors will bear the risk of the investment, and receive the profits from arbitraging the two markets, at least until DTe decides to exercise its option to absorb it into the regulated network. The main profit from the UKNLI derives from arbitraging imperfectly correlated spot prices in England and the Netherlands, rather than any fundamental difference in average prices, and such arbitrage is mutually socially beneficial. It reduces price volatility in both markets, increases security of supply and, unless the UKNLI is controlled by an importing incumbent, will reduce concentration in generation and improve the competitiveness of the Dutch and neighbouring markets. As a merchant interconnector, it relieves DTe of the burden of predicting whether the interconnector would be justified on social cost-benefit grounds, and hence justified as a regulated grid investment, while offering apparently positive benefits to Dutch consumers. These benefits may be enhanced by imposing various regulatory conditions, such as caps on control over the UKNLI, the requirement to trade capacity through APX, the requirement that capacity is subject to “use-it-or-lose-it”, and the right to exercise the option to absorb it into the regulated network. Provided these conditions do not reduce the size and attractiveness of the UKNLI, they will further enhance the social value of the interconnector, and would be worthwhile. If any regulation has an adverse effect on the size or viability of the UKNLI, then it would be necessary to balance the social gains from the regulation against the social cost of a smaller interconnection. Rough estimates suggest that the UKNLI is sufficiently privately profitable to make these issues of moderate significance.

We therefore recommend that DTe invite reactions to the consultation questions listed above, and assuming a favourable response, that it approve the UKNLI subject to the proposed regulatory conditions.
Bibliography