

**LONG-TERM RESERVE CONTRACTS
IN THE NETHERLANDS**

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Introduction and Summary

As in many European Countries, the Dutch energy debate has recently focused on security of supply. The Dutch Ministry of Economic Affairs, DTe and TenneT have studied a range of mechanisms that could enhance security by encouraging generators to build or retain capacity.¹ The Ministry has concluded that, if any mechanism is required, *the best option is to increase the amount of power that TenneT procures under long-term contracts*. Long-term contracts would provide generators with a stable source of income, helping to defer plant retirement and to facilitate the construction of new plant.

Ensuring supply security might require significant increases in the amount of capacity subject to long-term contracts. Consequently, TenneT may need to change the way it acquires long-term contracts. Auctions should replace bilateral negotiations to ensure optimal results, so the Ministry is naturally interested in auction design. The Ministry is also interested in the potential impact of additional contracts on energy prices. The Ministry has commissioned *The Brattle Group* to examine these, and other, issues, and to design a possible mechanism for implementation. The objective of this study is not to determine what type of additional measures would best enhance security of supply – the Ministry has already decided to focus on long-term contracts. The objective is to design an efficient mechanism that involves long-term contracts.

We begin with a description of the current balancing market (section 1), before discussing the types of reserve products that could support a desired level of supply security (section 2). We then discuss the effect that a support mechanism might have on consumer's costs and balancing prices (section 3) before going on to consider some detailed issues related to the operation of our recommended contract type (section 4). We conclude with recommendations concerning the optimal auction design for awarding contracts (sections 5 and 6).

We are grateful to TenneT for help in describing the details of the balancing mechanism, to DTe for useful comments, and to Professor Cornelli of London Business School for her help with auction design.

Which type of 'product'?

One potential scenario for the Dutch power market involves prices that would not be high enough to recover the fixed costs of approximately 1,000 MW of plant between 2005 and 2010. This capacity would likely retire, reducing the Dutch reserve margin significantly unless replaced by new capacity or new interconnectors. Peak² units are

¹ The Ministry's investigations into security of supply are summarised in the document "Electricity in Balance – Investment in electricity: between public interest and private responsibility". Section 7 of this document addresses alternative mechanisms for incentivising investment in electricity generation capacity.

² Some people use the term "peak" to describe units that routinely operate during daylight on weekdays, but not at night or weekends. However, we limit our definition of "peak" to units that rarely run, but that remain available in the event of unusual spikes in demand or outages in other units.

most likely to retire, because they have high operating costs, despatch infrequently and depend on uncertain price spikes. The uncertainty of price spikes may deter the market from building or maintaining peak capacity on the system. However, peak plant makes a valuable contribution to security of supply. Peak plants tend to have low capacity costs, and are well-suited to meeting infrequent demand spikes that test system security of supply. Therefore, a long-term contract mechanism concerned with maintaining security of supply should focus on peak plant. Initially, deferring the retirement of peak plant is the cheapest way to maintain the reserve margin.

TenneT could sign two types of contracts. TenneT could sign contracts that either require a 15-minute response time or permit slower responses. To distinguish between the two options, we have called the short-response option ‘PTU reserve’ and the other option ‘slow-response reserve’. Both types of contracts, or ‘products’, can help support peak-plant, but in different ways and with different costs. We devote significant discussion in our report to the choice between products, since PTU reserve has the obvious attraction of simplicity: TenneT already offers PTU reserve, while contracts for slow-response reserve might require a significant change in TenneT’s operating rules, responsibilities and authority. However, we find that slow-response reserve offers significant advantages that outweigh the administrative ease of purchasing additional PTU reserve.

Generating units can only provide PTU reserve if they are already running. They would have to commit to running “part-loaded” one day in advance, deliberately leaving part of their capacity unutilised and available to respond quickly the next day. PTU reserve is likely to come from plants with low variable costs that would normally run at baseload or mid-merit. Removing the capacity of these units from the day-ahead market, to provide additional PTU reserve, would require the despatch of more expensive peak units as a substitute. Contracting more PTU reserve will increase the despatch of all peak plants and increase their revenues, encouraging the market to maintain or build more peak capacity. However, using PTU reserve to enhance security of supply would significantly increase the average cost of electricity generation.

In contrast, slow-response reserve can increase security of supply more efficiently. Peak plant would be attracted to a slow-response reserve contract that did not require commitments to run in advance. Peak plant could provide slow-response reserve for almost the entire year, collecting revenues for the service while still running only infrequently when demand was unusually high relative to supply. Using peak plant to provide slow-response reserve would not disrupt the merit order significantly, and would not increase generation costs.

We conclude that it is cheaper to maintain the reserve margin using slow-response reserve as opposed to PTU reserve. To maintain a margin of 20% between domestic capacity and peak demand between 2005 and 2010, we estimate that a PTU reserve product would cost the Netherlands an average of €100 million a year. To achieve the same margin with a slow-response product would cost €23 million a year, four times less. Therefore, *we recommend signing contracts for slow-response reserve.*

Using slow-response reserve would depart from TenneT’s current operating practice. Efficient system management might require TenneT to develop projections of system

imbalance costs perhaps two or three hours in advance, to assess the benefits of calling slow-response reserve. TenneT would have more responsibility, possibly requiring new operating guidelines, and perhaps new financial incentives. Nevertheless, the cost savings offered by slow-response reserve give ample justification for such changes. We are confident that with the necessary reforms TenneT could optimise the use of slow-response reserve to reduce system costs, since changes to the rules in England and Wales have already permitted NGC to do so.

Allocating Costs to Customers

The optimal quantity of slow-response reserve will depend on the Ministry's desired security-of-supply standard, which is the subject of a separate study. Simply for illustration, we have calculated the costs for two levels of contracted reserve (500 MW and 950 MW). We recommend that TenneT allocate the costs of the additional reserve across all consumers, based on their power use at times of greatest imbalance. We understand that the current electricity law would prevent such an allocation, but note that adopting a 'causer pays' principle of charging for reserve would reduce security-of-supply costs. To maintain an average reserve margin of 20%, the average cost to consumers would be at least 0.2 €/MWh if TenneT allocated costs in proportion to energy use. This represents an increase of about 17% in the 2004 ancillary service charge.

Product Design

We have examined the existing arrangements for regulation and reserve to draw lessons for the design of the slow-response product. Like the existing arrangements, our proposed slow-response reserve contracts would oblige generators to offer energy in the balancing market. We assess whether the balancing market has any disadvantages that might complicate attempts to attract sufficient capacity under long-term contracts.

We compare the APX to the balancing market. Our analysis identifies no inherent disadvantages for the balancing market. If a generator has chosen not to participate in the APX, the generator should prefer participation in the balancing market relative to "self-balancing", which describes the intentional withholding of capacity for internal use or in bilateral contracts to avoid imbalance charges. The balancing market offers the attraction of ensuring the maximum utilisation of available resources. Our analysis suggests that generators should self-balance principally with units that could not actually participate in the balancing market: *i.e.* units that cannot respond to despatch requests within 15 minutes. A slow-response product should be attractive for the units that generators currently retain to self-balance. Since our proposals would create a centralised market for slow-response units, it should improve efficiency relative to the current practice of self-balancing.

We propose that slow-response reserve contracts operate in a similar fashion to TenneT's existing contracts for regulating power. TenneT's auction would ask competing generators how much money they require to sign the long-term contracts. We call this the 'capacity price', which we recommend should not be subject to a price cap. Once signed, the contracts would oblige the generators to make 'energy' offers to the balancing market, but these would not be specified as part of the contract terms. We recommend imposing a

cost-based cap on the energy offers. Note that, as in today's market, a cap on energy offers would not usually cap balancing prices, which are often set by un-contracted generators who have no restrictions on their offer price. We estimate that use of slow-response reserve could reduce balancing prices by, at most, seven percent, and the impact could be significantly smaller depending on how often TenneT uses the product.

We also propose giving TenneT the responsibility and authority to verify whether committed units are indeed available to provide reserve on particular days. A verification system would prevent generators from seeking to collect payments for units that cannot operate because of required maintenance or other reasons. We estimate that the cost of verification would be less than €1 million a year, although this would depend on how much slow-response reserve TenneT contracted.

Auction Design

We recommend that TenneT award reserve contracts based only on the capacity prices offered. Generators should not have to make energy-price offers at the time of the auction. We further recommend the adoption of a uniform-price auction, where the highest accepted offer sets the price for all contracts awarded. We prefer a uniform-price auction mainly because of its attractiveness to smaller generators. We also propose that the auction should be limited to a single round, each participant should be prohibited from making more than two offers per auction, and auctions should be held infrequently. These measures should minimise the risk of collusion. We also describe fall-back measures in the event that the auction does not succeed.

The auction should involve contracts with different start dates. We recommend 'current' contracts, which commence soon after each auction, together with 'futures' contracts, which would not require generators to provide reserve until three years later. The 'current' reserve contracts would expire when the futures contracts start providing reserve. Futures contracts should facilitate the construction of new units. The futures contracts should constitute around half the expected reserve requirement.

After the auctions, generators should have the freedom to trade their contractual obligations in a secondary market. TenneT and/or the Ministry should be proactive, establishing a secondary market even before the first auction. Generators are more likely to participate in the auctions if they know that an organised secondary market will facilitate trading afterwards.

Summary of main recommendations

- A long-term contract mechanism concerned with maintaining security of supply should focus on peak plant. Increases in baseload demand can be left to the market to resolve (page 12).
- TenneT should contract for a new form of reserve product – slow-response reserve – with a response time chosen so that idle plant can provide the product (page 21).
- DTe should consider the introduction of an incentive system for TenneT with regard to system balancing costs (page 22).

- The Ministry and DTe should consider changing the electricity law to allow TenneT to allocate the cost of reserve contracts according to a customer's load at the time of maximum system imbalance. This will reduce reserve costs and increase security of supply (page 23).
- TenneT should apply a cost-based cap to the energy offers from slow-response reserve (page 31).
- TenneT should test slow-response once a month to verify availability while avoiding the need for excessive penalties to motivate compliance (page 33).
- TenneT should extend the duration of its existing contracts for regulating power, but this measure is not a substitute for contracting slow-response reserve (page 37).
- TenneT and DTe should take an active role in establishing a secondary market for slow-response reserve contracts (page 50).
- Auctions for slow-response reserve should be infrequent, single-round and uniform-price. TenneT should restrict generators to making two price-quantity offers, and should forbid generator consortia (section 5).

1 The current Dutch Regulation and Reserve market

The existing contracts for regulation and reserve serve as the starting point for the new contracts. It is therefore important to understand how the current balancing market works. In this section, we explain the current balancing system and how generators supply balancing power.³

1.1 Demand in the balancing market

Dutch generators and consumers buy and sell electricity in three main ways: Over-The-Counter (‘OTC’)⁴, on the Amsterdam Power Exchange (‘APX’) and in the balancing market. Electricity on the OTC market can be traded anything up to several years before the electricity will actually be used. Equally, some OTC trades take place at the day-ahead stage. The organised APX only involves trades for electricity that will be consumed the next day. The APX is effectively an auction system that involves 24 simultaneous, uniform-price power auctions. For each hour of the following day, The APX runs a separate auction and produces a distinct price, using offers and bids from both generators and consumers. Economists use the term “two-sided”⁵ to describe auctions where consumers and suppliers offer and bid simultaneously.

The balancing market is also a series of short-term power auctions, with an auction held for every 15 minute period or Programme Time Unit (‘PTU’). However, in contrast to the APX, the balancing market auction is one-sided, because only suppliers make offers. Only TenneT can decide to buy and sell power in the balancing market. The point at which demand intersects the offer curve sets the balancing market price.

The Dutch balancing market is based on a system of Programme Responsible Parties (PRPs). Each PRP must submit an electricity off-take programme – called an E-programme – for every 15 minute PTU of the following day. The E-programme is based on all electricity sales and purchases made before 12:00 a.m. the day before despatch. For example, an energy retailer who is a PRP could submit a programme to use 100 MWh during every 15-minute period of the following day. The supplying generator would submit a matching E-programme. Balancing market prices would apply to each PRP for any differences between the energy actually consumed and the E-programme. “Positive” balancing power includes additional generation or reduced demand, while “negative” balancing power involves reductions in generation or additional demand. Positive and negative balancing power can face different prices, if TenneT has to buy and sell power within the relevant PTU. Otherwise the prices on both sides of the balancing market are

³ For more detail on the Dutch balancing market, see “The imbalance pricing system as at 1 January 2001” version 2.1, 01 February 2001, available at www.tennet.nl.

⁴ We use the term OTC to cover both brokered and bilateral trades.

⁵ Note that throughout this document, a bid is the proposed price for *buying* a unit of a good, and an offer is the proposed price for *selling* a unit of a good. As generators sell reserve to TenneT, we are principally concerned with offers.

the same. However, PRPs with positive balancing volumes *receive* the balancing market price whilst PRPs with negative balancing volumes *pay* the balancing market price. When calculating a PRP's imbalance position, TenneT considers any of the PRP's offers or bids that TenneT accepted in the balancing market.

1.2 Supply to the balancing market

On the supply side, Regulation and Reserve Power Suppliers ('RRPSs') provide both positive and negative balancing power. Large loads can act as RRPSs, but, in practice, the majority of RRPSs are electricity generators. Throughout this paper we assume that RRPSs are generators, unless stated otherwise. By one hour before a PTU, RRPSs have to specify an offer price for power in €/MWh, up to a specified limit (MW). RRPSs can offer upward power (increased generation) or bid downward power (decreased generation). In this paper, we focus on the provision of upward regulation and reserve, because it contributes to security of supply in the event of a major power supply failure.

There are currently three types of balancing power on the supply-side of the balancing market: regulation, reserve and emergency power. Regulation has the fastest response time, and RRPSs who offer regulation must be able to provide additional power rapidly.⁶ Regulation offers can be called at any level up to the maximum capacity specified. Reserve power has a slower response time, of around 15 minutes, and can only be called fully and for the whole PTU. On average in 2003, about 500 MW of upward regulating power and about 100 MW of upward reserve were available in each PTU. However, regulation provided over 95% of the energy in the balancing market.

As the name implies, emergency power is used when 'spare' regulation and reserve capacity has dropped to very low levels. One can think of emergency power as a special subset of reserve power, which differs from 'normal' reserve only in that it is used last, is contracted on a long-term basis with set energy prices, and is verifiable. Unlike regulation and reserve, emergency power is mainly provided by interruptible load. When emergency power is called, it sets the price for imbalance shortages at a relatively high price (around 2000 €/MWh). TenneT currently contract 300 MW of emergency power, although it is used very rarely.

The response times of plants have implications for their despatch. Regulating plant can be despatched as and when required according to the demand for balancing energy, subject to ramp-up and ramp-down constraints. However, because of the longer (15 minute) and less flexible response of reserve plant, TenneT has to take a somewhat longer-term view in determining their utilisation. In practice, TenneT uses judgement in deciding when to call reserve plant. For example, TenneT may despatch reserve if the amount of un-despatched regulating power falls below 100 MW, but TenneT could despatch reserve before this point, if it is aware of special circumstances. In addition, TenneT can despatch plant at the day-ahead stage to overcome expected transmission

⁶ Regulating power must be able to increase output at a rate of 7% of the maximum capacity offered per minute. For example, a plant offering 100MW of regulating power would have to deliver 35MW within five minutes.

constraints. The units that address transmission constraints might not have to meet the performance criteria for reserve.

Regulating power is dispatched in order of increasing offer prices.⁷ Note that even if reserve has a lower offer-price than regulating power, TenneT will not call reserve until required for operational reasons. In an economic sense, TenneT treat reserve and regulation as two different products; an increase in the prevailing price of regulating power will not result in an increase in demand for reserve. If reserve is needed, then TenneT calls reserve in order of increasing offer price. In each PTU, the highest dispatched offer from either regulation or reserve sets the balancing price.⁸

The law requires all generating plants larger than 60 MW to offer uncommitted capacity to TenneT. In practice, offering spare capacity to TenneT does not require active participation in the balancing market. Connected parties can simply offer power to TenneT with a longer response time than the 15 minutes required for reserve. TenneT cannot currently use these offers in the balancing market, because the offers cannot be called within a PTU period. TenneT may occasionally accept these offers to solve infrequent transmission constraints, but the offers play no part in setting balancing prices. Alternatively, generators may avoid the balancing market by offering capacity with a 15-minute response time, but with such high prices as to preclude acceptance under most circumstances.

1.3 Contracted and uncontracted suppliers

In the previous sections, we distinguished between upward and downward regulation and reserve power. Another important distinction involves the contractual relationship between TenneT and suppliers of balancing power. There are currently two types of RRPSs in the Dutch balancing market: generators that offer regulation and reserve power on a daily basis, and generators that hold long-term contracts with TenneT, which oblige them to offer a minimum amount of regulating power daily. For convenience, we use the term ‘contracted suppliers’ to describe generators with long-term contracts, and we call the other RRPSs ‘uncontracted’.

TenneT holds contracts for 250 MW of regulating power. Contracted suppliers provide roughly half the available regulating capacity.⁹ TenneT negotiates these contracts on a bilateral basis with generators, and the contracts typically last for one year. Generators who hold contracts with TenneT receive a capacity payment for making

⁷ The exception to this is if transmission constraints prevent dispatch of the cheapest available regulating offer. In this case, a more expensive but unconstrained offer will be called. However, the need to call out-of-merit-order offers due to transmission constraints happens very infrequently.

⁸ TenneT can also apply an incentive component, which adds a spread between the price suppliers of balancing energy receive and buyers of balancing energy pay. However, the incentive component has been set to zero since 17 October 2002, and so we do not consider it further in our discussion.

⁹ TenneT also has 300 MW of emergency power contracted. Emergency power contracts are partly contracted abroad, the domestic part currently consists of interruptible load contracts only.

regulating power available, whether or not it is used. Uncontracted suppliers receive no capacity payment. They simply receive the prevailing price for the energy they sell in the balancing market.

Regulating power contracts involve generator commitments on a portfolio basis, and do not involve specific units. Contracted suppliers must make offers on the balancing market for all PTUs, up to the contracted capacity limit. Contracted suppliers must make offers within limits related to the previous day's APX price. For upward-regulation power offers, the contracts typically cap energy bids at the APX price corresponding to the PTU plus 185 €/MWh. For downward-regulation power bids, the contracts typically prevent the bid from falling below the relevant APX price minus 50 €/MWh. Un-contracted suppliers face no limits to their bids.

2 For which products should TenneT contract?

In the interest of improving security of supply, TenneT could tender for more regulating, reserve or emergency power, or for a new product. In this section we examine which product could maintain a reserve margin for the least cost. We evaluate alternative reserve products by calculating the additional cost *to Dutch society as a whole* of achieving a given reserve margin. We do not consider the cost to one particular group such as generators or consumers, or transfers between groups. Considering the costs to all groups avoids subjective trade-offs among the interests of different groups, such as a decision whether higher consumer prices are more or less important than increased generator profits.

To design an optimal policy for ensuring security of supply, the first step should involve a decision concerning the reliance on market forces as opposed to regulatory solutions. This choice underlies the alternatives that the Ministry, TenneT and DTe have explored. While providing definitive answers lies beyond the scope of this engagement, we hope to contribute by discussing briefly our international experience and our understanding of the Dutch market.

Few regulators or analysts in the United States would trust markets alone to provide optimal security. However, we see unique institutional factors that contribute to a fundamental mistrust of markets. For example, the California power crisis has put pressure on most regulators in the United States to intervene directly with security of supply. Moreover, the United States power industry has traditionally involved regulated utilities planning for sufficient resources backed by technical studies. U.S. Regulators find it easiest to continue applying this perspective in liberalised markets. In contrast, the British energy regulator (Ofgem) believes that markets will provide security of supply naturally. This view is founded partly on the demonstrated willingness of investors to build new plant in the UK, and partly on the abuse of the previous system of capacity payments.

We believe that Ofgem has been reasonable, and that the distrust of spot markets in the United States may be exaggerated. However, we see the small size of the Dutch market as a key distinction relative to the United Kingdom. The small size of the market implies a greater risk of experiencing a large amount of simultaneous accidental outages. The small size of the Dutch market requires a relatively large reserve margin – in percentage terms – to ensure efficient security levels. A large reserve margin requires a willingness from generators to build a relatively large amount of capacity that is rarely utilised and that, in the absence of any supplementary mechanism, must recover its costs from volatile spot markets. Furthermore, the Dutch market has not yet assembled the same successful history as in the United Kingdom, of new investors willing to build significant amounts of additional capacity. Our analyses of the Dutch market suggest that a large amount of plant may retire in the next few years. The small size of the Dutch market means that reserve margins can fall much more rapidly than in larger markets. We therefore sympathise with the desire to introduce long-term contracts that would supplement the revenues provided by wholesale power markets.

2.1 Long-term contracts should focus on peak plant

The purpose of the new long-term contracts is to ensure security of electricity supply in the Netherlands. In this report, we use the reserve margin¹⁰ as a proxy for security of supply.¹¹ The construction of new plant and the retirement of old plant are key determinants of the reserve margin. Our report therefore focuses on plant retirement and construction as the mechanisms of maintaining an adequate supply security.¹²

Most power systems have a mixture of peak and base-load generating plant. Peak plant has relatively low capital costs, but high operating costs. It makes economic sense to use peak plant to cover peaks in ‘effective demand’,¹³ which we use to describe an unexpected surge in demand or the failure of a generating unit or an interconnector. If a peak unit is despatched infrequently, its capital-cost advantage will be more attractive than its operating-cost disadvantage.

Conversely, baseload plants have high capital costs, but low operating costs. If a baseload plant runs frequently, its operating-cost savings will offset its higher capital costs. If there is a shortage of baseload capacity, then by definition the market will experience the shortage with regularity. Consequently prices should rise in a relatively steady and predictable way, and the market should respond by building new baseload plant.

In contrast, the market will notice shortages in peak capacity less frequently. While prices may increase dramatically when serious shortages occur, such ‘price spikes’ can be difficult to predict. Moreover, large price spikes can invite regulatory scrutiny and intervention. Therefore, owners of peak plant must rely on a volatile and unreliable revenue stream. This is especially true for plant that may only run several times a year during periods of extreme effective demand. Revenue risks may therefore prevent generators from maintaining or building new peak plant. The market may ‘fail’ in the sense of providing insufficient peak plant, yielding an inadequate reserve margin and excessive risk of supply interruption at times of high effective demand.

The Ministry has decided to introduce long-term contracts to foster security of supply. Since peak plant is the most efficient for addressing infrequent events that threaten

¹⁰ We define the reserve margin as (available supply minus peak demand) divided by peak demand. For example, if supply was 20 GW and peak demand was 15 GW, the reserve margin would be 33%.

¹¹ Note that the security of supply standard is the subject of a separate report commissioned by the Ministry.

¹² Note that there are other ways to improve the reserve margin and security of supply. For example, demand-side response measures – such as real time pricing – could be introduced, or interconnection capacity could be increased. However, such measures fall outside the scope of this report.

¹³ We define effective demand as load plus unexpected supply failures. Effective demand is a useful concept for security-of-supply discussions, because it equates the failure of a generator to increased consumer demand. Under both circumstances, available generators must supply more power.

security of supply, and since any market failure most logically involves peak plant more than base-load plant, *a long-term contract mechanism to promote security of supply should focus on peak plant*. In the rest of this report, we focus on a long-term contract mechanism that will initially prevent the retirement of existing peak plant, and that will later motivate the construction of new peak plant.

2.2 TenneT should only offer new upward-balancing contracts

As we mentioned previously, we focus on upward regulation and reserve because it contributes to security of supply in the event of a major power supply failure. Downward-balancing contracts cannot. Furthermore, baseload plants are more likely to win downward-balancing contracts. A plant must already be running to provide downward balancing, and baseload plants can run regularly at the lowest cost. Additional downward-regulation contracts would primarily reward baseload plant, but as we indicated above baseload plant is not the most cost-effective way of ensuring security of supply.

Moreover, it is not clear how having more downward-balancing contracts would increase the reserve margin. A downward-balancing contract does not prevent a base-load plant from selling power in the day-ahead market. The revenues from a downward-balancing contract would permit a base-load plant to charge lower prices in the day-ahead market while still obtaining satisfactory revenues overall. Having more downward-balancing contracts might prompt the construction of new baseload units that can ramp down fast, while reducing baseload prices in the day-ahead market sufficiently to prompt the retirement of baseload units that ramp down slowly. Shifting the balance of baseload plant towards faster response would offer security benefits, but would not improve the reserve margin.

The rest of this report only considers upward-balancing contracts. We note that TenneT's *existing* downward- regulating contracts will still be necessary for safe system operation.¹⁴

2.3 Alternative products

We consider two-classes of upward balancing products:

- PTU reserve – this product would conform to the existing regulation and reserve contracts, requiring power in 15 minutes or less. In practice, only plant that is already running can provide this type of product.
- Slow-response reserve – this product would have a response time of longer than 15 minutes. Its use in the balancing market would represent a change to TenneT's existing mode of operation. Idle plant, that is not running, could provide slow-response reserve.

¹⁴ TenneT should of course continue to contract for downward regulation, because this is required to operate the system. However, TenneT should not contract for significant *additional* amounts of downward regulation.

We first calculate the likely level of plant retirements in the absence of any new long-term contracts. Plants that are not recovering their fixed costs by selling electricity will (or should) retire.¹⁵ Such plants are typically old and inefficient, have a high marginal cost of production, and therefore do not despatch often, *i.e.* peak plant.

We have modelled the Dutch electricity market for the years 2005-2010, assuming that the current relationships between prices and short-run marginal costs persist (we provide details of the main modelling assumptions in Appendix I). We use an iterative approach to plant retirements. We first run our model assuming no retirements. We then examine the revenue for each plant, and retire plants that consistently lose the most money. We then re-run the model with these plant retired¹⁶ to see what impact their retirement has on the revenues of other plant. We continue this procedure until no plant loses more than 8 €/kW/yr between 2005 and 2010.¹⁷

In reality, retirement decisions are complicated, and our modelling of retirements is necessarily simplified. However, the basic premise – that generators will retire inefficient plant that is not covering its costs – is sound. The exact timing of retirements will naturally differ at least somewhat from our modelling results.

We estimate that, in the absence of any additional contracts from TenneT, the Dutch reserve margin of domestic capacity over peak demand could fall to 13% by 2010 (see Table 1). It is important to note that interconnectors with neighbouring countries are likely to make a positive contribution to the reserve margin. Therefore, using only Dutch generating capacity to calculate the reserve margin yields an unrealistically low number. For example, with full interconnector capacity included, the reserve margin in 2009 could approach 60%.¹⁸ In practice, the reliable capacity margin will be somewhere between these two extremes. If required, TenneT could reduce the level of retirements, and increase the domestic capacity reserve margin, by contracting for larger amounts of reserve.

In principal, TenneT could also contract for more emergency power. However, emergency power is, by definition, a form of reserve only used as a last resort. If TenneT contracted for more emergency power, it would be used more frequently, and in circumstances that were not system emergencies. Therefore, we treat larger amounts of emergency power simply as reserve, and do not consider emergency power further as a separate product.

¹⁵ In practice, plant may well be mothballed before it is fully retired. We do not distinguish between the two possibilities. In our model the plant is simply unavailable on the system, and does not contribute toward security of supply.

¹⁶ We assume all plant closures occur by the start of 2005.

¹⁷ We allow plant making such a loss to continue operating because we recognize that using characteristic days to represent a year under-estimates revenues for peak plant.

¹⁸ Based on 4,700 MW of current interconnector capacity, the NorNed cable (600 MW) coming in for 2008 and the BritNed cable (1320 MW) for 2009.

Table 1: Reserve margins with an without additional contracts for reserve

	2005	2010
Base case - peak plant retires	20%	13%
500 MW of peak plant retirement deferred	24%	17%
950 MW of peak plant retirement deferred	27%	20%

Contracting additional PTU reserve or slow-response reserve would reduce the amount of peak-plant retirements, and increase the reserve margin (see Table 1). However, the way in which the two products reduce retirements, and the cost of achieving a given reserve margin, differ.

2.4 Increasing reserve margins with a PTU reserve product

Only plant that frequently schedules to run in advance for at least a reasonable proportion of the day (what we call ‘running plant’ in this section) can provide the PTU reserve product at low cost.¹⁹ Consequently, only running plant would be willing to sign long-term contracts for PTU reserve.

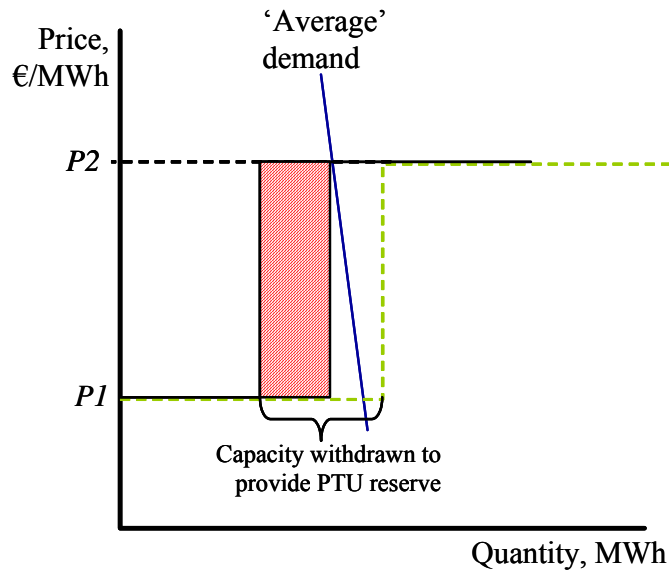
For simplicity, we measure a unit’s ability to provide regulation and reserve capacity as the difference between the plant’s maximum and scheduled output.²⁰ Generators must reduce their scheduled output to provide more upward regulation and reserve.²¹ Contracting for more PTU reserve would raise electricity prices by reducing the output of efficient running plant, requiring the despatch of more expensive plant that would then set prices. Peak plants would earn higher revenues, and fewer peak plants might retire. Figure 1 illustrates. As baseload generators reduce their despatch to provide PTU reserve, the price rises from $P1$ to $P2$. Less efficient peak-plant now generates the electricity that efficient running plant would have generated otherwise. Costs increase by the amount shown in the shaded rectangle in Figure 1.

¹⁹ There may also be opportunities for plant that run less frequently to provide PTU reserve during designated service windows. However, we assume a simple PTU product that must be available at all times.

²⁰ In practice, the plant will be able to provide less than this, because of ramp-rate constraints.

²¹ In practice, PTU reserve contracts would have to compensate running plants for reducing output, and forgoing an opportunity for profitable despatch in the wholesale market. We do not consider such payments in our analysis because they are redistributive in nature rather than necessarily being an additional cost to Dutch society as a whole.

Figure 1: Illustrative effect of withdrawing running capacity on price



TenneT would have to contract for a significant amount of PTU reserve to cause prices to rise sufficiently to keep peak plant on the system. Table 2 shows the volume of PTU reserve that would be required to prevent the retirement of 500 MW and 950 MW of peak plant. This varies significantly by year but, on average, we estimate that TenneT would need to contract an *additional* 1250 MW of PTU reserve to prevent the retirement of 500 MW of peak plants, and nearly 1700 MW of additional PTU reserve to prevent the retirement of 950 MW of peak plants.

TenneT would have to contract large amounts of PTU reserve to keep peak plant on the system, because PTU reserve contracts would increase imports before providing more revenues for domestic Dutch peak plant. Figure 2 illustrates the situation in 2005.²² Prices would rise in the Netherlands, but imports would receive a large fraction of the additional revenues. Increasing the amounts of PTU reserve would eventually exhaust the supplies of 'cheap' imports, and Dutch peak plants would then start to operate more frequently and earn increased revenues.

²² The 'base case' is the scenario in which TenneT does not contract for additional PTU reserve.

Table 2: Volume of PTU reserve required to defer peak plant retirements (MW)

	2005	2006	2007	2008	2009	2010	Average
Defer 500 MW of retirements	3000	1500	500	500	1000	1000	1250
Defer 950 MW of retirements	4000	2000	500	500	1500	1500	1667

Figure 2: The effect of additional PTU reserve on the Dutch supply curve in 2005

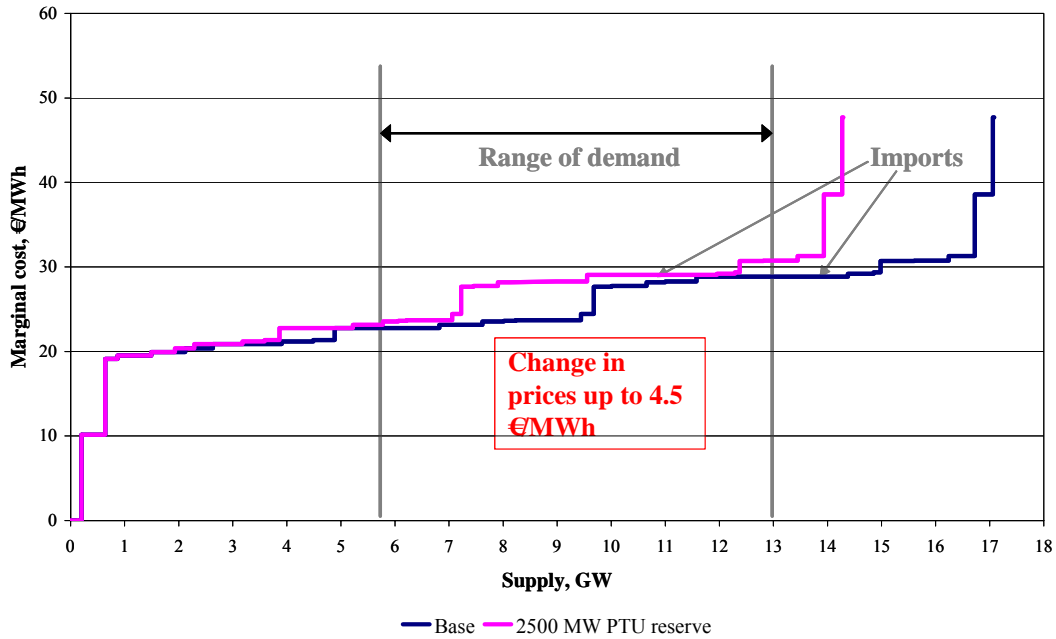


Table 3 details the effect of contracting additional PTU reserve on the mix of domestic generation, imports and the cost of generation, while Figure 3 shows how the level of net import varies with additional PTU reserve.

Table 3: Effect of additional PTU contracts on imports and generation costs

			2005	2006	2007	2008	2009	2010
500 MW of peak plant retirements deferred								
Increase in peak plant output (TWh)	[1]	TBG	4.0	2.2	2.1	2.0	1.2	1.4
Decrease in baseload plant output (TWh)	[2]	TBG	-13.2	-5.8	-1.7	-1.7	-3.5	-3.6
Increase in imports (TWh)	[3]	-[2]-[1]	9.2	3.6	-0.4	-0.3	2.3	2.2
Change in marginal costs of domestic plant (€/m)	[4]	TBG	-114.9	-31.0	30.7	27.4	-13.8	-11.2
Change in net costs of imports (€/m)	[5]	TBG	278.3	111.6	-9.9	-5.9	41.7	58.9
Increase in marginal cost due to use of PTU reserve, (€/m)	[6]	[4]+[5]	163.4	80.5	20.8	21.5	27.9	47.7
Increase in marginal cost due to use of PTU reserve, (€/MWh)	[7]	[6]/{-[2]}	12.4	13.9	12.2	12.3	8.1	13.3
950 MW of peak plant retirements deferred								
Increase in peak plant output (TWh)	[8]	TBG	5.5	3.0	2.5	2.3	1.7	2.0
Decrease in baseload plant output (TWh)	[9]	TBG	-17.2	-8.3	-1.7	-1.7	-6.2	-6.3
Increase in imports (TWh)	[10]	-[9]-[8]	11.7	5.3	-0.8	-0.6	4.4	4.4
Change in marginal costs of domestic plant (€/m)	[11]	TBG	-137.4	-50.5	43.2	37.2	-39.6	-37.2
Change in net costs of imports (€/m)	[12]	TBG	351.3	154.8	-30.0	-18.2	98.3	113.4
Increase in marginal cost due to use of PTU reserve, (€/m)	[13]	[11]+[12]	213.9	104.3	13.1	19.0	58.7	76.2
Increase in marginal cost due to use of PTU reserve, (€/MWh)	[14]	[13]/{-[9]}	12.4	12.6	7.6	10.9	9.5	12.0

Figure 3: Imports with varying amounts of PTU reserve

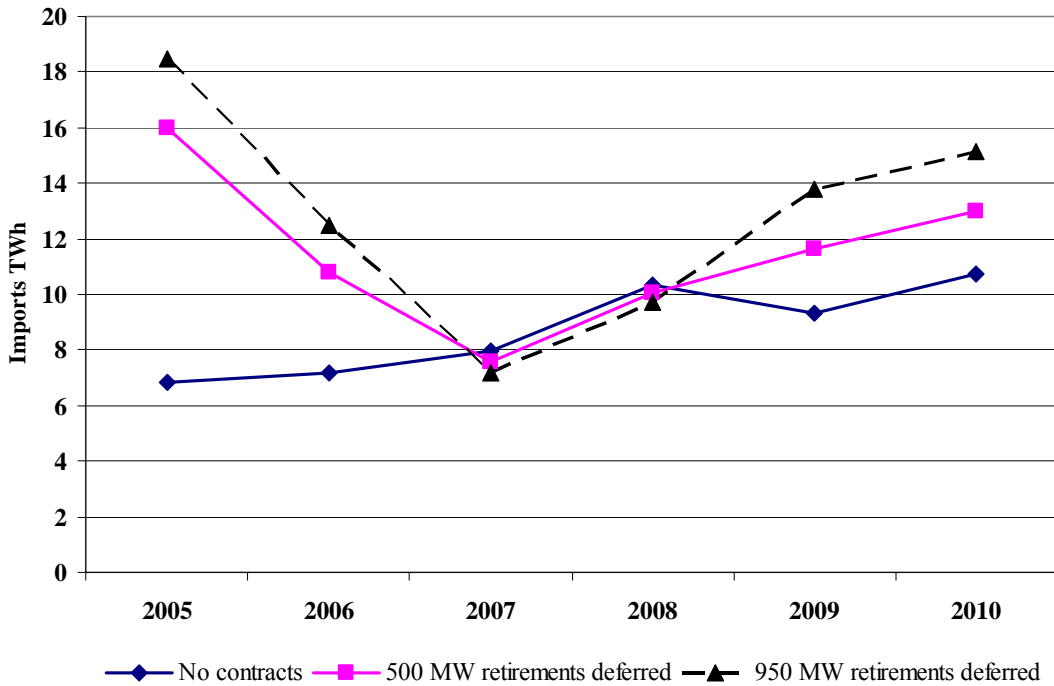
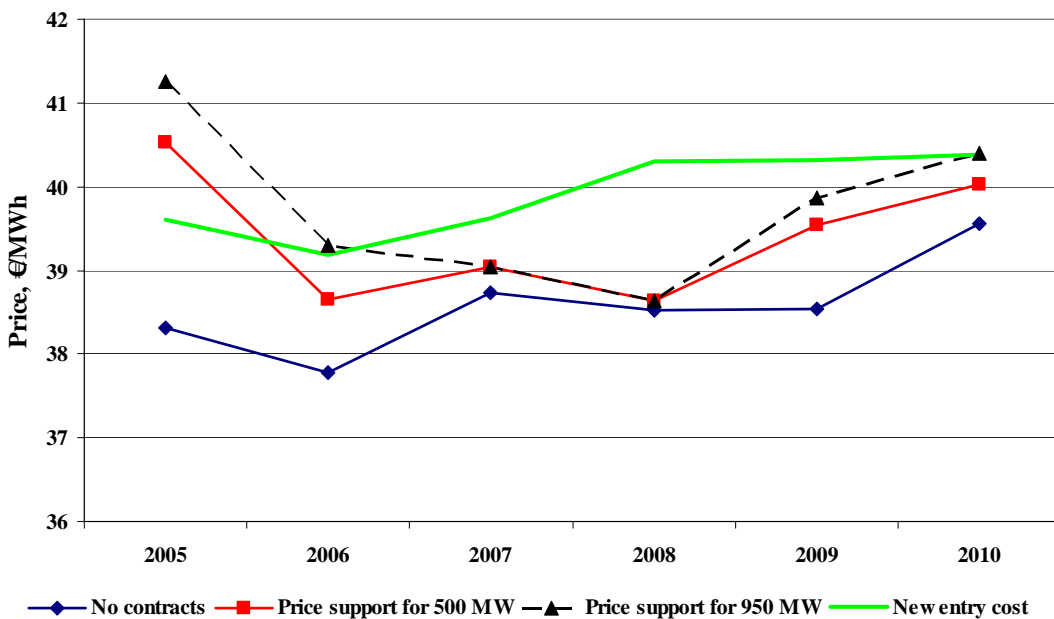


Figure 4 shows the prices that result from contracting different levels of PTU reserve. Supporting 500 MW and 950 MW of peak plant via additional regulation contracts would require average price increases of 2% and 3% respectively, relative to the base case. We note that at these price levels, the construction of a new CCGT would still not be attractive in most years.

Figure 4: Wholesale electricity prices with additional PTU reserve

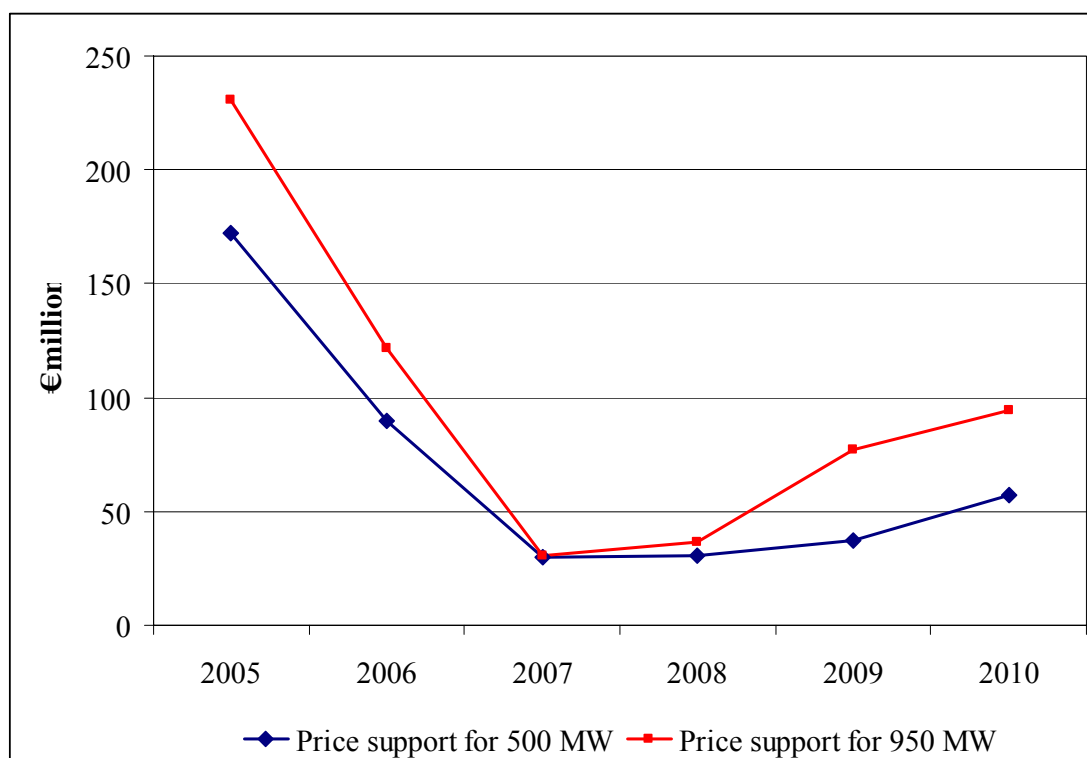


The preceding analysis assumes that the Norned cable will be commissioned in 2008 and the Britned cable in 2009. Cancellation of both interconnectors would eliminate the need for additional PTU reserve to keep 950 MW of plant on the system from 2008 onwards. Peak plant would naturally run more often in the absence of the new interconnectors, earning more revenue and covering costs. In other words, the interconnectors reduce the despatch and revenues for domestic peak plant.

Cost of providing security of supply with additional PTU reserve

Using PTU reserve to keep peak plant on the system imposes two costs on society: the fixed costs of the peak plant, and the additional cost of generating electricity from less efficient peak plant (the shaded rectangular area in Figure 1). The latter cost is the more significant. Figure 5 illustrates the costs of using PTU reserve for maintaining two different levels of peak plant capacity. Table 4 on page 21 summarises the numbers.

Figure 5: Cost of deferring peak plant retirements using a PTU reserve product



2.5 Increasing reserve margins with slow-response reserve product

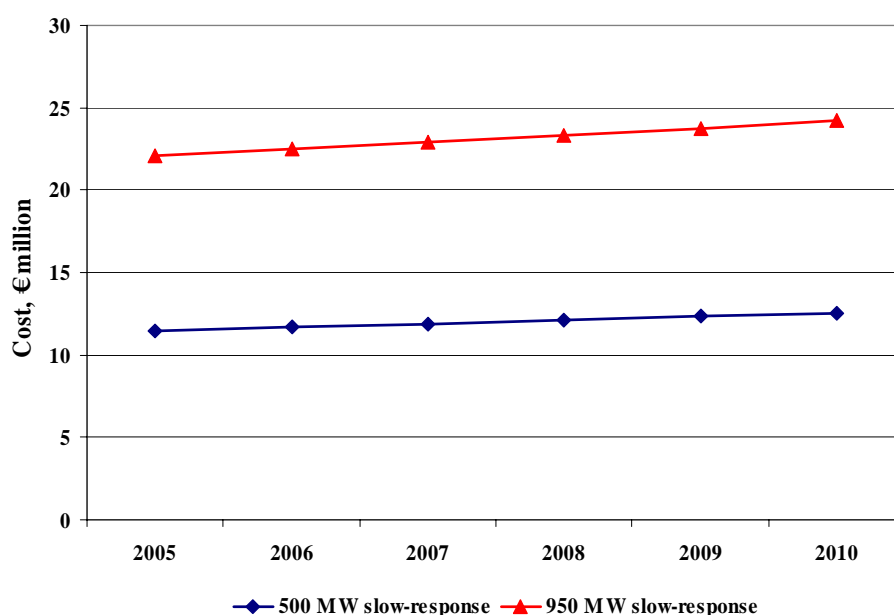
By committing to provide reserve, generators forgo potential profits in the day-ahead energy market: they incur an ‘opportunity cost’. The opportunity cost of providing reserve will be lowest for peak plants, because such plants will rarely despatch anyway. Plant can provide slow-response reserve without committing to run in advance, because of the relatively long response time allowed. Accordingly, peak plant should find it attractive to provide slow-response reserve. To avoid retirement, we expect that peak units would demand sufficient capacity payments to cover their fixed costs. There would be little effect on wholesale prices, since the plants providing slow-response reserve

rarely set prices. In sum, using slow-response reserve has a capacity effect, but little or no energy effect: it maintains or increases the capacity on the system, with minimum disruption of energy markets. Increasing PTU reserve is the opposite: it provides a small capacity effect by inducing a large energy effect, shifting energy production to less efficient units.

Cost of providing security of supply with slow-response reserve

The costs to society of slow-response reserve are the fixed costs of the most expensive peak plant that would have retired in the absence of the contracts. Figure 6 illustrates how these costs vary over time. Broadly speaking, costs should increase with inflation (*i.e.* they remain constant in real terms), since the plant under contract does not change. Table 13 and Table 14 in Appendix V give more details of the costs.

Figure 6: Cost of deferring peak plant retirements using a slow-response reserve product



2.6 Liquidity and market power

The effect of additional reserve contracts on liquidity

Most commentators think of a liquid market as one where large volumes trade, where many traders are active, and where prices are robust to relatively large trades. Both slow-response reserve and PTU reserve would affect liquidity, but in different ways.

As we note above, the plants that provide slow-response reserve would have rarely run in the wholesale market, so their withdrawal from the market should have little effect on the volumes traded. The withdrawal of some peak plant from the day-ahead market will reduce supply options, which can reduce liquidity. However, the availability of more peak plant in the balancing market will improve balancing-market liquidity. Since prices in the day-ahead market will depend in part on forecast balancing-market prices, we find

it difficult to believe that day-ahead prices would become significantly less robust to large trades.

The PTU-product involves the withdrawal of between 2,500 MW and 3,000 MW of power from the wholesale market. However, more expensive peak plant and imports would replace this capacity, leaving little net effect on volumes in the wholesale market. Importing more power would imply more trades on the APX, since all imports must go through the APX. Liquidity might increase. However, contracting more PTU reserve may make prices more sensitive to demand, by shifting trading activity to a steeper part of the supply curve. The resulting volatility could reduce liquidity. It is not obvious whether additional PTU reserve would increase or decrease liquidity in the short term, but we see no reason to think that any change would be significant.

In the long run, use of either product should improve liquidity when considering the day-ahead and balancing markets combined. Either product would help prevent plant retirements and motivate the construction of new plant. Having more total capacity should improve liquidity.

Market power

Moving plants from one market to another should make little difference to generators' ability to exercise market power. At first glance, contracting additional reserve might seem to increase market power in the day-ahead market, by removing available plant. However, any attempt to raise prices on the day-ahead market would shift more consumption to the balancing market. Because consumers can substitute between electricity markets, ownership concentration across *all* markets (*e.g.* the OTC market, APX *etc.*) is the relevant consideration. Additional reserve contracts would not change overall ownership concentration, and so should not affect generators' ability to exercise market power. In practice, substitution between markets may not be perfect. Some market power effects might arise, but they are unlikely to be significant. By reducing generator risk and facilitating the construction of new plant, our proposed contractual mechanism should improve competition in the long run.

2.7 Conclusion on product type

Both the PTU reserve and the slow-response reserve defer peak plant retirements, and support investment in new peak plant. With both products the Netherlands must bear the fixed costs of peak capacity that otherwise would have been retired or never built. With the slow-response reserve, the fixed cost of peak plant is the only additional cost to society. However, contracting more PTU reserve would impose an *additional* cost. Higher-cost peak capacity would replace the lower-cost running capacity that generators set aside for PTU reserve. The average cost of electricity generation would increase.

Table 4 illustrates the cost of maintaining additional peak plant capacity of 500 MW and 950 MW using a PTU reserve product and a slow-response reserve product.²³ We

²³ All costs and prices shown are in money-of-the-day *i.e.* prices are adjusted upwards for inflation.

give more details of the costs in Appendix V. To maintain an average reserve margin of 20% using PTU reserve contracts costs an average of €100 million every year. To do the same using slow-response reserve costs an average of €23 million every year, four times less.

Table 4: Summary of costs of PTU and slow-response reserve

		2005	2006	2007	2008	2009	2010
Slow response reserve							
Cost of 500 MW	€m	11.4	11.7	11.9	12.1	12.3	12.6
	€/MW	22 894	23 381	23 806	24 240	24 681	25 132
Cost of 950 MW	€m	22.1	22.5	22.9	23.4	23.8	24.2
	€/MW	23 215	23 709	24 140	24 580	25 028	25 485
PTU reserve							
Cost to defer 500 MW of retirements	€m	172.1	89.5	30.0	30.8	37.3	57.3
	€/MW	344 284	179 049	59 923	61 549	74 686	114 681
Cost to defer 950 MW of retirements	€m	230.8	121.6	30.7	36.9	77.0	94.7
	€/MW	242 994	127 989	32 364	38 834	81 028	99 732

Our calculations indicate that contracting additional PTU reserve is significantly more expensive than contracting slow-response reserve. We recognise that contracting additional PTU reserve has operational advantages for TenneT (discussed in more detail in section 2.8). However, these operational advantages cannot justify the costs associated with contracting additional PTU reserve. If the Netherlands wishes to make a step change in its security of supply arrangements, this will require changes in the way TenneT manages the system. Attempting to underwrite security of supply with the existing balancing products would result in excessive costs for Dutch consumers. It is also mistaken to think that there is some optimal combination of contracting for additional PTU reserve *and* slow-response reserve. PTU reserve will always be more expensive than slow-response reserve. Therefore, contracting more PTU reserve than required for operational reasons will create excess costs. *We recommend that TenneT contract for a slow-response reserve product*, which we describe in section 4.

2.8 TenneT's role in the balancing market

TenneT is responsible for balancing supply and demand in the Dutch power system on a second-by-second basis. TenneT must choose between despatching regulation or reserve power. TenneT currently calls reserve purely for operational reasons *i.e.* if the amount of remaining regulating power is low. It is not currently TenneT's role to reduce balancing costs by, for example, replacing relatively expensive regulating power with cheaper reserve offers. TenneT points out that demand uncertainties make it difficult to reduce system balancing costs, and could even result in increased costs. The time restrictions on reserve power mean that it would only reduce costs if TenneT reliably anticipates a sustained need for upward regulation. Reserve must be called for a full 15 minutes, and in practice must also have time to ramp up and down. Reserve despatched in one period will likely persist into subsequent periods. If the market moved suddenly from

an anticipated power deficit to a ‘long’ position with excessive power, TenneT would not be able to cancel the upward reserve power. The market might witness the costly, simultaneous despatch of upward reserve and downward regulation: ‘two-sided balancing’. Approximately 30% of PTUs already involve two-sided balancing, which implies that the system changes from being long to short in at least one out of every three PTUs.²⁴ TenneT believes that the despatch of reserve on economic grounds would increase the number of PTUs with two-sided balancing, which is apparently unpopular with market participants. Slow-response reserve could exacerbate the problem, because TenneT would need to forecast imbalances further ahead than with the current reserve product. In sum, efficient use of a slow-response product relies on the ability to forecast imbalances.

While imbalances are unpredictable, international experience suggests that TSOs can successfully predict and manage imbalances. In England and Wales, the regulator introduced new regulations and financial incentives that together prompted NGC to achieve dramatic reductions in the cost of system balancing (see Appendix VII for details). We have no reason to believe that the Dutch system is less predictable than the British one, or that cost reductions would be more difficult. Giving TenneT a similar role may require changes to regulations, operating guidelines and incentives. We do not recommend any fundamental alteration to TenneT’s role without implementing the necessary changes.

If the Ministry seeks a mechanism to promote security of supply, slow-response reserve would offer the best value for Dutch consumers. Using slow-response reserve requires TenneT to forecast further ahead of despatch, with increased risks of errors. We therefore recommend that DTe consider the introduction of an incentive system for TenneT with regard to system balancing costs.

²⁴ A period of two-sided balancing implies that the system has changed direction in terms of the sign of system imbalance. For example it could mean that the system changed from being long at the beginning of the PTU to being short at the end of it, or *vice versa*.

3 The effects of the new contract mechanism

3.1 Cost allocation

Who should pay?

The balancing market would pay for the energy costs of slow-response reserve, but TenneT would need a mechanism to recover the cost of the capacity payments.²⁵ TenneT could attempt to allocate the capacity costs to PRPs whose imbalances required the despatch of slow-response reserve. In practice, causation can be difficult to determine. Moreover, there is a strong case for spreading the capacity costs of slow-response reserve among all users (cost socialisation), as all consumers benefit from the service in the form of improved security of supply.

Some large customers, who are prepared and able to be interrupted, may not wish to pay for additional security of supply. The simplest way to accommodate these customers would be to allow them to offer reserve (including slow-response reserve) and emergency power. If their offers are accepted, their income from the reserve sold will offset the additional charge they have to pay for the capacity payments of slow-response reserve. Any other method of accommodating interruptible customers would be considerably more complicated and raise verification issues.

TenneT currently recovers the costs of regulation and emergency power via the system services tariff. The tariff is set in €/kWh, and so users pay in proportion to their energy consumption. We understand that charging in this way for reserve is a legal requirement.²⁶ However, reserve requirements are not closely related to energy consumption throughout the year. Reserve requirements relate more closely to consumption at the time of the system's maximum power deficit. Therefore, it seems more logical to allocate the cost of reserve capacity according to a consumer's load at the time of highest balancing prices. Specifically, we recommend that TenneT allocate the capacity costs of the reserve contracts according to the average of a consumer's load at the three hours of the year with highest imbalance prices, because this represents the three most 'difficult' hours of system operation *i.e.* where demand most exceeds supply, requiring the most reserves. We note that such an allocation mechanism should encourage some larger consumers to try to reduce their consumption at difficult hours, so that they will pay a smaller share of the capacity costs. This would further improve security of supply, by reducing system demand when the system is most short of power.

²⁵ Note that the *cost* and the *price* of the capacity contracts are not the same. The *price* of capacity is set by the generator with the highest fixed costs (see section 5.4). Therefore, the price for capacity payments will in general be higher than the costs of providing capacity. However, according to our calculations, this difference is small for the Dutch system (*i.e.* the supply curve for reserve capacity is fairly flat), and so we treat the costs and price of reserve as equivalent.

²⁶ Article 30.3 of the Dutch electricity law stipulates that kWh consumption must be used for the system service charge. Article 30.1 stipulates that costs for regulation, reserve and emergency power must be covered through system service charge.

3.2 Anticipated cost of the contracts to consumers

The cost of the new slow-response reserve contracts to Dutch consumers will depend on the quantity of reserve contracted, which in turn will depend on the chosen security of supply standard. We calculate the additional costs to Dutch consumers for two levels of slow-response reserve. We recommend allocating costs according to consumption during the hours with the highest imbalance prices, but it is difficult to predict when such hours would occur. We therefore perform calculations that allocate costs in proportion to demand at peak hours, which should tend to be the hours with highest imbalance prices. We also perform calculations that illustrate the potential allocation of costs according to a customer's energy use throughout the year.

Table 5 illustrates that contracting 500 MW of slow-response reserve would require an increase in the charge to grid operators of 0.76 €/kW, equivalent to a 16% increase. Allocating the cost to the ancillary services charge would increase the charge by 0.1 €/MWh, an increase of 9%. The costs increase in proportion to the amount of contracted slow-response reserve, as shown in Table 6. Note that the numbers presented represent the *lowest* possible price that consumers would pay for slow-response reserve, because they are based on generation costs. In practice, generators may be able to charge above cost because the market is not perfectly competitive. Therefore, the actual costs to consumers could be about 20% higher than shown in the tables below (based on current Dutch wholesale price mark-ups).

Table 5: Costs to consumers for 500 MW of reserve capacity

		2005	2006	2007	2008	2009	2010
Cost of capacity contracts, € million	[1] TBG	11.45	11.69	11.90	12.12	12.34	12.57
Costs allocated on a maximum kW used basis							
Maximum measured demand, GW	[2] See note	15.05	15.36	15.66	15.98	16.30	16.62
Capacity payments, €/kW	[3] [1]/[2]	0.76	0.76	0.76	0.76	0.76	0.76
Grid operator's charge without capacity payments	[4] See note	4.74	4.74	4.74	4.74	4.74	4.74
Grid operator's charge with capacity payments	[5] [3]+[4]	5.50	5.50	5.50	5.50	5.50	5.50
Increase in grid operators charge, %	[6] {[3]/[4]}x100	16%	16%	16%	16%	16%	16%
Allocated on a kWh basis							
Dutch energy use, TWh	[7] See note	114.9	117.2	119.5	121.9	124.3	126.8
Capacity payments, €/MWh	[8] [1]/[7]	0.100	0.100	0.100	0.099	0.099	0.099
Ancillary services charge without capacity payments, €/MWh	[9] See note	1.12	1.12	1.12	1.12	1.12	1.12
Ancillary services charge with capacity payments, €/MWh	[10] [8]+[9]	1.220	1.220	1.220	1.219	1.219	1.219
Increase in ancillary service charge, %	[11] {[8]/[9]}x100	9%	9%	9%	9%	9%	9%

Notes

[2]: Based on a measured demand of 14.47 GW in 2003, and assuming a growth in peak demand of 2% per year

[4], [9]: Based on the 2004 tariff, which we assume stays constant in real terms.

[7]: Based on consumption of 110.4 TWh in 2003 (provided by UCTE), and assumed demand growth of 2% thereafter

Table 6: Costs to consumers for 950 MW of reserve capacity

		2005	2006	2007	2008	2009	2010
Cost of capacity contracts, € million	[1] TBG	22.05	22.52	22.93	23.35	23.78	24.21
Costs allocated on a maximum kW used basis							
Maximum measured demand, GW	[2] See note	15.05	15.36	15.66	15.98	16.30	16.62
Capacity payments, €/kW	[3] [1]/[2]	1.46	1.47	1.46	1.46	1.46	1.46
Grid operator's charge without capacity payments	[4] See note	4.74	4.74	4.74	4.74	4.74	4.74
Grid operator's charge with capacity payments	[5] [3]+[4]	6.20	6.21	6.20	6.20	6.20	6.20
Increase in grid operators charge, %	[6] {[3]/[4]}x100	31%	31%	31%	31%	31%	31%
Allocated on a kWh basis							
Dutch energy use, TWh	[7] See note	114.9	117.2	119.5	121.9	124.3	126.8
Capacity payments, €/MWh	[8] [1]/[7]	0.192	0.192	0.192	0.192	0.191	0.191
Ancillary services charge without capacity payments, €/MWh	[9] See note	1.12	1.12	1.12	1.12	1.12	1.12
Ancillary services charge with capacity payments, €/MWh	[10] [8]+[9]	1.312	1.312	1.312	1.312	1.311	1.311
Increase in ancillary service charge, %	[11] {[8]/[9]}x100	17%	17%	17%	17%	17%	17%

Notes

[2]: Based on a measured demand of 14.47 GW in 2003, and assuming a growth in peak demand of 2% per year

[4], [9]: Based on the 2004 tariff, which we assume stays constant in real terms.

[7]: Based on consumption of 110.4 TWh in 2003 (provided by UCTE), and assumed demand growth of 2% thereafter

3.3 Effect of slow-response reserve on balancing prices

The impact of slow-response reserve on balancing prices will depend on TenneT's use of the product. We illustrate with two extreme cases. First, TenneT may only use slow-response reserve infrequently, perhaps only after despatching emergency power. In this case, slow-response reserve would have a negligible effect on average balancing prices. Second, TenneT could use slow-response reserve frequently, to try and reduce average balancing prices and system costs.²⁷ For example, TenneT could despatch slow-response reserve whenever regulating power seemed relatively expensive. We cannot specify the behaviour of slow-response reserve in the balancing market. Unknown variables include the required notice period for slow-response reserve, the minimum time period that slow-response would run for, and TenneT's control over the power. For this exercise, we assume that slow-response reserve is as inflexible as the current reserve product: it must be called for a full PTU. We also assume that TenneT would only despatch slow-response reserve when anticipating a relatively extended imbalance period. If TenneT had good forecasting skills, it could use slow-response reserve more often. The most extreme case is where TenneT has perfect foresight, predicting future imbalances perfectly. We model this case, because it involves the maximum use of slow-response reserve, and therefore the maximum possible effect on balancing prices.

To predict the effect on balancing prices in this scenario, we take 2003 imbalance prices and demand. We then model a case where TenneT despatches slow-response reserve, if it "forecasts"²⁸ that for four PTUs in succession the market will be short of power and the forecast price is above a certain threshold. In other words, slow-response reserve must run for at least one hour, and its use must result in a price reduction. In our

²⁷ If one assumes that generator's balancing-energy price-offers broadly reflect their underlying costs, then a reduction in balancing prices will translate to a reduction in costs.

²⁸ Since we are using historic data on imbalances, actual imbalances form TenneT's forecast i.e. we assume perfect foresight.

model, the total dispatch of slow-response reserve depends on the minimum demand for balancing power over the relevant period. This avoids situations of excess power in the market. We recalculate the balancing price assuming certain energy bids from slow-response reserve, and the ability to displace some balancing power on the bid ladder. For example, the market could be short for five PTUs in succession, the average forecast price (without slow-response reserve) over these PTUs could be 300 €/MWh and the lowest demand for balancing power in this period could be 200 MW. In this case, 140 MW of slow-response reserve would be called for five PTUs, regulating power would be reduced by 140 MW and the average price could fall to 170 €/MWh. Appendix II gives a more detailed description of our analysis.

Table 7 illustrates the potential effect of slow-response reserve on balancing prices in our extreme cases. Balancing prices drop by 7% on average assuming perfect foresight by TenneT. The greatest reductions occur during months where balancing prices are highest. Table 7 also illustrates that the average price received by providers of slow-response reserve is 210 €/MWh. To have lower average balancing prices would imply fewer revenues for uncontracted units that provide balancing energy. However, contracting for slow-response reserve would permit peak plants to sell balancing energy, when normally they could not meet the 15-minute response times of PTU reserve.

Table 7: Effect of slow-response reserve on balancing prices €/MWh

	Maximum Price All PTUs		Average Price All PTUs			Average Price 'Short Only' PTUs		Average Price for PTUs in which slow response reserve called		
	Without slow-response reserve	With slow-response reserve	Without slow-response reserve	With slow-response reserve	% fall	Without slow-response reserve	With slow-response reserve	Without slow-response reserve	With slow-response reserve	% fall
2003										
January	987	987	41	40	2%	118	113	302	268	11%
February	369	363	37	37	0%	79	78	175	169	3%
March	380	380	14	14	2%	91	85	258	155	40%
April	338	338	30	29	3%	100	95	188	150	20%
May	336	332	41	40	4%	103	98	199	167	16%
June	706	685	63	56	12%	146	119	375	241	36%
July	631	501	41	37	9%	148	122	318	194	39%
August	1984	1984	93	81	13%	203	167	561	409	27%
September	420	420	51	50	2%	110	105	210	177	15%
October	1300	1016	81	64	20%	203	137	381	199	48%
November	1011	985	89	80	10%	159	131	286	205	28%
December	1435	1435	83	77	7%	134	118	238	188	21%
Average			55	50	7%	133	114	291	210	25%

Table 8 shows the number of PTUs in which slow-response reserve is used. Even in the extreme scenario, slow-response reserve is only used in around 5% of PTUs.

Table 8: Frequency of slow-response despatch

Month	Number of PTUs in which slow response reserve called	Percentage of PTUs in which slow-response reserve is called
January	55	1.8%
February	63	2.3%
March	7	0.2%
April	65	2.3%
May	136	4.6%
June	157	5.5%
July	86	2.9%
August	229	7.7%
September	106	3.7%
October	265	8.9%
November	333	11.6%
December	356	12.0%
Average	155	5.3%

3.4 Effect of slow-response reserve on generator incentives

By contracting for slow-response reserve on a long-term basis, TenneT could change a generator's incentives with regard to building or maintaining capacity. The potential change in incentives will depend on the policies announced. For example, if TenneT announces that it would offer contracts to all capacity that was about to be retired, then TenneT's announcement may prompt more declarations of intentions to retire capacity. Generators may prefer a long-term contract with TenneT over the uncertainty of energy markets. Instead, TenneT should be clear that it is not willing to contract for ever increasing amounts of slow-response reserve to maintain security of supply. TenneT should also be clear that it does not intend to expand the amount of slow-response reserve that it contracts in future, and that any un-contracted plant that announces its intention to retire will be allowed to do so. These measures should minimise any distortions to generators' incentives. We also note that the security of supply standard – and how this standard is applied – will strongly affect generators' incentives. However, the security of supply standard is the subject of a separate study commissioned by the Ministry.

4 Product Design

In this section, we consider a number of issues connected with the detailed design of the product. First, we describe some principles that should govern the notice provisions in the reserve contracts. Second, we examine the current incentives that generators may have to ‘cheat’ on their current TenneT contracts for regulating power, by simultaneously offering power to the APX. This provides some insights for avoiding abuse by slow-response reserve. Third, we consider the potential need for price caps on energy offers by slow-response reserve. Again, we begin by considering the effect of the current caps on offers for contracted regulating power. Fourth, we discuss the need for mechanisms to verify the availability of slow-response reserve. Finally, we discuss the advantages of a centralised market for slow-response reserve.

4.1 Notice provisions

TenneT should design slow-response contracts to encourage participation by peak plant. Accordingly, the contracts should give idle (*i.e.* not running) peak plant sufficient time to start up, while also limiting the response time to something of practical use to TenneT. To accommodate these potentially conflicting objectives, we recommend allowing TenneT to instruct slow-response reserve to start up and remain ‘warm’. In ‘warm’ mode, generation units would be spinning, but would not be synchronised to the system. Warm plant should be able to produce power within 60 minutes of a further instruction from TenneT. Plants would receive an agreed lump-sum payment for start-up and an hourly payment while in warm mode, which would cease when and if the plant was despatched. TenneT should give all slow-response reserve the same warm-up notice, regardless of the actual warm-up time the plant needs. Contracts of this nature are used by other TSOs, notably that National Grid Company (NGC) in England & Wales.

4.2 Arbitrage between day-ahead and balancing markets

Generators essentially have three options for deploying their capacity. First, they can offer it in the wholesale market, either day-ahead or via a longer-term contract. Second, they can offer it as regulation or reserve in the balancing market.²⁹ Third, they can use the power for self-balancing.

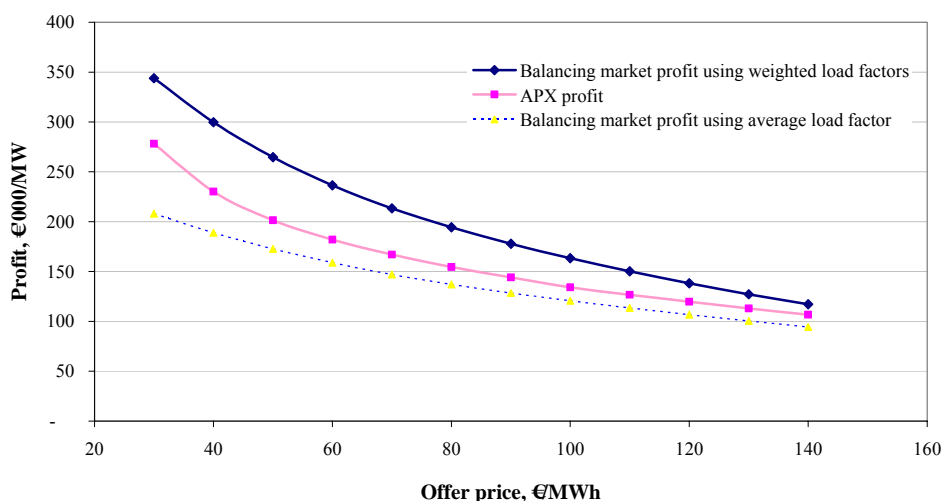
If there is active arbitrage between the day-ahead and balancing markets, it would be reasonable to worry that generators who hold contracts for regulating power in the balancing market might “cheat” by offering same the power in the day-ahead market. We have analysed the relative attractiveness to generators of the day-ahead market and the balancing market. We calculated the profit than a generator would make offering an

²⁹ The generator is only able to offer balancing power if the additional MW comes from plant that is already generating. In other words, an offer of a MW on the balancing market is contingent on a large quantity of power being accepted to run in the day-ahead market. The quantity of power accepted in the day-ahead market must be large enough and persist long enough to justify plant start up and operation at the minimum output of the plant or more.

additional MW of generation on the APX market or as regulating power in the balancing market, using 2002 and 2003 prices.³⁰

Whether the balancing market is more profitable than the APX depends strongly on the assumed load factor for a generator *within* a PTU. For example, we assume that generators are despatched in the balancing market when their offer price is below the prevailing balancing market price. However, it is unlikely that their full offer would be accepted for the entire PTU. We therefore make various assumptions about how much of the generator's offer is called on average during a PTU. Depending on the assumptions made, the balancing market can be either more or less profitable than the day-ahead market, Figure 7 illustrates our results. We describe our methodology in Appendix III.

Figure 7: Profit per MW in the day-ahead and balancing market for 2002/3



Economic theory suggests that profits in the two markets should be approximately the same. If the balancing market offered higher profits than the day-ahead market, generators would shift move supply to the balancing market. Increased supply in the balancing market would reduce profits, until they approximated the profits in the day-ahead market. Our analysis seems to be in line with economic theory since profits in the balancing market and the APX market are approximately equal, depending on the assumptions made about the pattern of despatch within a PTU. This suggests that there is active arbitrage between the two markets.

³⁰ It is not possible to analyse the attractiveness of offering reserve in the balancing market as a function of the offer price. Reserve is not necessarily called when its offer price is below the prevailing balancing price, but rather when it is required operationally. The balancing price could be substantially above the offer price of reserve, but yet reserve may not be called.

4.3 The need for price caps with the existing regulation contracts

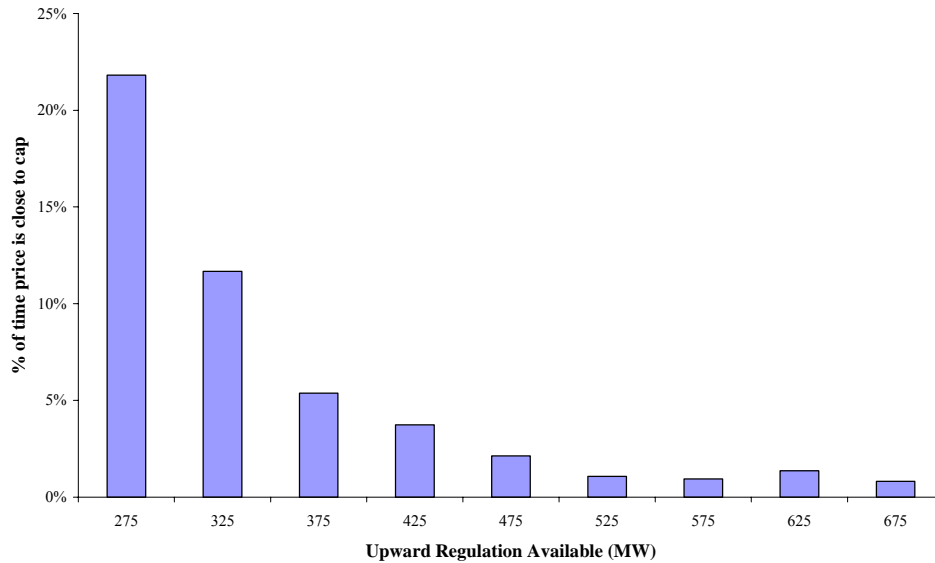
We have examined the effectiveness of the caps that TenneT currently applies to contracted regulating power. We understand that TenneT limits upward-regulation offers to the corresponding APX price for a PTU, plus 185 €/MWh.³¹ Generators are free to offer regulating energy at a price lower than the offer cap, but offers cannot exceed the cap. The pool of generators who currently supply regulating power is likely to be similar to the pool that will provide long-term reserve power. Therefore, it is instructive to see how often generators who are currently under contract offer power at or near the price cap. As we can only observe prices (and not offers), we have examined prices during periods when the majority of regulating power offered is from generators under long-term contract *i.e.* when offered regulating power is close to 250 MW.

Figure 8 illustrates the percentage of time that prices are at – or just below – the offer cap. When the amount of regulating power is between 250 and 300 MW, prices are at or near the offer cap for nearly 25% of the time. This indicates to us that there is not vigorous competition between the long-term providers of regulating power. It is difficult to estimate the precise effect of removing the offer cap on prices, because it is impossible to say if – when the cap is removed – the generators with long-term contracts would continue to set the price or not. However, if we assume that when the amount of regulating power was less than 400 MW, generators with long-term contracts would continue to set the balancing price, then raising the offer cap to APX+1500 €/MWh could increase average balancing prices by around 10%.

We also investigated if relatively high APX prices could explain the high frequency of prices near the cap level. However, we found no significant difference in the average APX price when the average level of available regulation was 275 MW and when it was about 400MW.

³¹ Not all of the long-term contracts specify a energy-price offer cap in this form. Some of the contracts specify the cap as a multiple of the corresponding APX price. However, we understand that the majority of the contracts specify the offer cap in the form given above.

Figure 8: Frequency that prices are near the offer cap as a function of available regulating power



4.4 Price caps on energy offers of slow-response reserve

A cap on energy offers by slow-response reserve could prevent concerns of potential abuse. We do not know how many generators currently hold contracts for regulating power. Perhaps a more diverse set of generators will hold slow-response reserve contracts, promoting greater competition. Nevertheless, it would be wise for TenneT to impose a cap on energy offers from holders of slow-response reserve contracts. Otherwise, providers of slow-response reserve may be able to extract high energy prices when the system is short of power. In the absence of capacity payments, high peak prices are necessary to finance peak plant. However, contracted generators receiving high balancing prices would in effect be paid twice for providing peak power – first through the capacity payment and then through energy payments.

Note that *a cap on energy offers for slow-response reserve would not act as a cap on balancing market prices*, or would even cap the prices received by slow-response reserve. Slow-response reserve would receive the prevailing balancing price, probably set by an un-contracted provider of regulating power. For example, from the calculations described in section 3.3, we calculate that providers of slow-response reserve would receive an average price of 210 €/MWh, despite assuming that their offers never exceed 150 €/MWh. The offer price cap would simply limit the offers by slow-response reserve providers, and the frequency with which they set balancing prices.

While we recommend an energy offer cap for slow-response reserve, we do not recommend linking the cap to APX prices. We prefer setting the cap by reference to the estimated maximum marginal cost of a peaking unit. This will minimise any formulaic

link between balancing prices and day-ahead prices.³² The offer cap should be indexed to gas prices at a liquid trading hub and cover the marginal costs of the most expensive peak plant.

4.5 Verification of slow-response reserve

Capacity payments raise the issue of verification. Without verification, a generator could collect money for peak plant even when it is not really available. For example, a generator could offer reserve power at a very high price, to reduce the likelihood of despatch. The generator could then use the ‘reserve’ power to generate electricity for the day-ahead market, or could take the plant down for maintenance. The generator would still receive reserve capacity payments, and the chance of TenneT finding out that the reserve was not actually available might be small.

A system to verify availability might be desirable, particularly because slow-response reserve is likely to have a lower chance of being called than regulation, even if TenneT caps the energy offer price. Therefore selling reserve to TenneT while simultaneously using the capacity for electricity generation could be a profitable strategy, because the chance of TenneT detecting such cheating is low.³³

We conclude that TenneT should conduct regular, but random, tests on slow-response reserve offers to ensure that cheating on reserve offers is not a profitable strategy. A verification system implies that *generators must associate reserve offers with specific plant*. If slow-response reserve offers were not associated with a specific plant, TenneT would have to test the entire offer from each generator. Otherwise, generators could still cheat without detection. For example, a generator could offer 100 MW of slow-response reserve, but actually only have 50 MW of reserve available. TenneT could test 50 MW on one day, and do another 50 MW test the following day. However, the same plant would provide the reserve for both tests. Unless TenneT asked for a single 100 MW test, TenneT could not be confident that 100 MW of reserve is actually available. However, conducting tests on a generator’s entire reserve offer could prove impractical and costly.

In contrast, if generators state which units underwrite their slow-response reserve offers, TenneT can test smaller amounts of capacity and be confident that the entire reserve offer will be available. Generators would only need to specify which plants underwrite their offers, once TenneT had accepted their offer in the auction. Generators should be permitted to change the identity of the supporting reserve units on a regular

³² Such a link could lead to price inflation in the day-ahead market, if buyers were certain that balancing prices would *always* be higher than day-ahead prices, they would raise their bids to avoid being out of balance.

³³ We expect that relatively old and high-marginal cost plant would provide the majority of the slow-response reserve. This would reduce the problem of ‘double-selling’ reserve, because such plant is unlikely to be able to generate competitively in the wholesale market. However, without a verification system, generators might be tempted to sell TenneT slow-response reserve using lower marginal cost plant that they could use for wholesale generation.

basis. TenneT should also have inspection rights to visit and inspect any reserve plant at any time and at short notice.

Plants will occasionally fail verification tests, not because they are cheating, but because a technical fault results in a failure to start-up. However, TenneT should not make allowances for such failures. For example, TenneT should not exempt generators from a penalty if they prove the existence of a genuine technical problem. Confirming such technical failures would be time-consuming and difficult, and would remove any incentive for generators to improve their start-up performance. Nor is it necessary for TenneT to set a ‘target’ number of allowed failures. As long as generators are aware of the testing frequency and the penalty rates before they make their capacity offers, they can account for their likely number of failures and adjust their offers accordingly.

Testing frequency and penalties

Penalties should apply when generators fail to deliver slow-response reserve. TenneT should design the penalty to remove any financial incentives to cheat by offering plant that is not really available. *The penalty level will therefore depend on the testing frequency.* For example, if each generator expects to be tested every month, then the penalty should be at least equal to the capacity payments for a month. Another useful form of penalty could require the generator to sacrifice all capacity payments until it passes a subsequent capacity test. Higher penalties are necessary to prevent cheating if testing periods are relatively infrequent.

If TenneT tested plant very infrequently, for example once every year, the penalty for failure would need to be very large to make cheating unprofitable. As discussed above, generators will occasionally fail a verification test for technical reasons. Therefore, generators would worry that they have to pay a large penalty because of a ‘legitimate’ technical failure. This risk might dissuade them from signing a contract for slow-response reserve, or might lead them to increase their capacity offer prices substantially, to accommodate the possibility of failing a verification test. Therefore, we recommend limiting the size of the penalty to a value that is unlikely to concern generators unduly. This implies that the verification should be reasonably frequent. A verification frequency of one test per unit per month is likely to result in an acceptable penalty level.

We note that verification is more important if TenneT is unlikely to call slow-response reserve frequently. If TenneT aimed to minimise the overall cost of system balancing, it might use slow-response reserve somewhat more often. This would reduce the need for verification, because it would increase the risk of being caught ‘cheating’. For example, Table 8 illustrates that slow-response reserve could be called up to 5% of the time on average, and in some months over 10% of the time, implying that cheating on reserve agreements would be difficult. If TenneT moves to a cost-minimising approach to system balancing, the need for verification of slow-response reserve should be reviewed.

Effect of verification on prices

For the purposes of verification, TenneT may need to call out of merit slow-response reserve offers, when there is sufficient regulating power available to operate the system. Consequently, if the tested units are allowed to set prices, verification could affect

balancing prices, either upward or downward. Tested units could displace lower energy offers from regulation, prompting an increase in the balancing price, or replacing expensive regulating offers. As a result, plant testing could arbitrarily reward or penalise out-of-balance PRPs. To avoid this, TenneT should calculate balancing prices based on a bid ladder that ignores the tested units. The tested units should be paid their energy offer prices.

The cost of verification

Use of slow-response reserve causes a verification cost. There are no verification costs associated with the use of regulating power (or PTU reserve), because regulating power is used so frequently that no verification is required. Therefore, it is worth considering if the extra costs of verification could significantly offset the cost advantage calculated for slow-response reserve in section 2.7.

The costs of verification depend on the particular hours when tests occur. If TenneT conducted a test when the market was short of power, and balancing prices were relatively high, the test could actually reduce balancing costs. If TenneT conducted the test when the market was long then it would be much more expensive. For example, TenneT may have to pay the generator under test 200 €/MWh, but the balancing price may be only 20 €/MWh. TenneT would have to fund the 180 €/MWh difference.

We examine two scenarios. First, TenneT simply calls slow-response reserve at random, and makes no attempt to schedule tests when the market is short. We have calculated that the average price for RRPSs supplying power in 2003 was 55 €/MWh. If TenneT scheduled tests randomly, tested generators would receive 55 €/MWh from the balancing market, and would possibly demand additional amounts from TenneT. Suppose the energy offer cap was 200 €/MWh for providers of slow-response reserve, then, on average TenneT would have to refund the generator under test the difference between the balancing price and the generators offer price, equal to 145 €/MWh. Assuming that TenneT tested 500 MW of slow-response reserve every month, and the test duration was 30 minutes (two PTUs), verification would cost TenneT less than €0.5 million every year. Table 9 illustrates the calculation.

Table 9: Maximum cost of verification

Test data			
Average short imbalance price in 2003, €/MWh	[1]	TBG	55
Slow-response reserve offer price, €/MWh	[2]	TBG	200
Slow-response to be tested, MW	[3]	TBG	500
Tests per month	[4]	TBG	1
Length of tests, PTUs	[5]	TBG	2
Costs			
Price difference funded by TenneT, €/MWh	[6]	[2]-[1]	145
Annual cost of testing, €	[7]	[6]x[3]x{[5]/4}x12	435,000

However, TenneT could reduce the cost of testing significantly, and possibly even eliminate it, if it called tests when the market was short of power. Our work on

quantifying the effect of slow-response reserve on balancing prices suggests that, on average, it should be possible to test about 1700 MW of slow-response reserve per month while actually *reducing* balancing costs (see Appendix II for more details). This number exceeds the likely level of slow-response capacity that TenneT would seek in any auction.

Therefore, the cost of verification is likely to be small or even negative, and will not affect the conclusion that slow-response reserve is significantly cheaper than PTU reserve for maintaining the reserve margin. We recommend that TenneT establish a ‘test fund’ to pay for test costs. One possibility would be to set TenneT a target for the cost of testing, and to let TenneT keep a percentage of the savings if the actual tests costs are lower than the target.

4.6 A central market for slow-response reserve

Generators have a choice between offering uncommitted capacity in the balancing market and keeping the power for self-balancing.³⁴ We conclude that *it is always optimal for a generator with uncommitted power – with a response time of 15 minutes or less – to offer this plant in the balancing market* (see Appendix IV for more details). Offering in the balancing market does not eliminate any possibilities for self-balancing, and creates an opportunity for profitable despatch in the balancing market. If generators do not make meaningful offers for plant in the balancing market, it seems likely that their response time exceeds 15 minutes.

TenneT has indicated that generators offer many plants to the balancing market with longer response times than 15 minutes. TenneT suspects that generators *prefer* to keep plant for self-balancing, to reap operational advantages. For example, despatch instructions in the balancing market are only given over a 15-minute time horizon. With self-balancing, generators are free to schedule plant more flexibly, including for several hours at a time. However, generators should not lose any flexibility by offering balancing power. They are free to deviate from despatch instructions if they wish and will still receive the prevailing balancing price for any additional output that they produce. However, generators with plants that cannot meet the response times required in the balancing market must keep this ‘slow-response’ reserve for themselves, or trade it bilaterally with other generators.

The introduction of slow-response reserve as a new product would effectively create a centralised market in which generators could trade a large pool of units that have response times greater than fifteen minutes. Even generators who do not hold long-term slow-response reserve contracts could offer this product on a daily basis in the balancing market, in the same way as generators who currently offer regulation. Organising slow-response reserve as a formal balancing product could have various efficiency benefits. At present, generators must trade slow-response reserve bilaterally. For example, imagine two generators, A and B. Generator A has 100 MW of capacity in reserve that is available within one hour. Generator B has a failure of 100 MW, and consequently goes out of

³⁴ As explained earlier, while technically they may have to offer spare capacity to TenneT, they can in effect use this capacity for self-balancing by submitting long response times.

balance. Generator A can agree to start-up his reserve plant and sell the output to Generator A. This will limit Generator B's imbalance duration to one hour. However, relying on such bilateral trades may not always be efficient. In the example above, Generator B has to know that Generator A has reserve available, and then make a deal to buy the power. If Generator B did not know that there was relatively cheap reserve available, it would have to rely on more expensive regulating power in the balancing market.

Alternatively, Generator B could offer its reserve to TenneT as slow-response reserve. When Generator A experiences a failure, it could inform TenneT of the failure and its likely duration. If this duration is several hours, it would be worth TenneT starting up cheaper, slow response reserve. The incentive on Generator A to inform TenneT of the likely duration of the outage is that balancing prices should reduce, as a result of TenneT despatching cheaper reserve. In this situation, Generator A does not have to find the generator with spare reserve, because there is a central market for this product. *A centralised market reduces the transaction costs of finding reserve and avoids inefficient outcomes.*

Slow-response reserve and a new adjustment market

An on-the-day adjustment market might be introduced in the Netherlands. The adjustment market would handle trades after day-ahead gate closure up to a few hours before despatch. One approach to security of supply could involve the design of slow-response reserve contracts that oblige generators to make offers in this new adjustment market, rather than the balancing market.

However, an obligation to bid in the adjustment market may not guarantee the availability of reserve capacity. Depending on the detailed design of the market, generators could offer the contracted reserve capacity onto the adjustment market at a very low price, and bid to buy the same amount of capacity back at a very high price. They would have fulfilled their contractual obligation, but would be free to sell the same capacity elsewhere simultaneously. There would be no additional reserve available, and no contribution to security of supply. For this reason, *we do not see a role for slow-response reserve in the adjustment market.*

Nevertheless, the adjustment market could provide important information to TenneT by indicating when it might be appropriate to call slow-response reserve. High prices in the adjustment market could be a good leading indicator of a shortage, revealing opportunities to despatch slow-response reserve economically.

4.7 Extending the term of the existing regulation contracts

TenneT currently contracts for 250 MW of regulating power. The contracts last one year. As an alternative to introducing slow-response reserve, TenneT has proposed extending the duration of the contracts – perhaps three years – to provide greater revenue certainty to generators. Longer-term contracts could help support new plant, or defer the retirement of existing plant. This would improve security of supply.

We support TenneT's proposal to increase the duration of regulating contracts to about three years. We can identify no disadvantages to the proposal, and agree that longer-term contracts would help reduce the risk of investment in new plant. However, it is not possible to model quantitatively the effect that longer-term term regulating contracts would have on investment, the reserve margin and security of supply. Nevertheless, we can recommend the introduction of longer-term regulating contracts because they would be cheap to introduce, have no identified disadvantages, and offer clear advantages.

We note, however, that *introducing longer-term contracts for regulating power should be viewed as a complement to, not a substitute for, slow-response reserve*. As we have discussed previously, only running plant can provide regulating power under long-term contract. Increasing the duration of regulating contracts would provide greater certainty for investment in baseload plant, but would provide little assistance to peak plant. Consequently, longer-duration regulating contracts would be unlikely to prevent the retirement of peak plant, and may lead to an increase in the share of baseload plant. This would not be the most cost-effective way to maintain the reserve margin.

5 Design of the long-term contract auction

5.1 Form of the long-term contracts

A generator holding a long-term slow-response reserve contract will receive a payment (€/MW/year) for every MW of capacity contracted by TenneT. An auction would determine the size of the capacity payment for the new contracts. The contracts would then oblige the generator to offer the contracted number of MW to TenneT for system balancing.

Because the contracts oblige generators to offer slow-response reserve to TenneT, and because a verification system would enforce these obligations (see section 4.5), generators would not be able to export power during periods of peak demand. This contrasts with some other arrangements for reserve (such as an Operating Reserve market) where generators are not under long-term contract and can therefore export power at times of peak domestic demand.

We assume that, as now, TenneT will dispatch long-term contract holders on the basis of their energy offers. TenneT will continue to set balancing prices within a 15-minute PTU, and the highest energy offer dispatched will set the price for the PTU. All generators who supply energy within the PTU will receive the balancing price. In effect, there is an energy auction in every PTU with a single market clearing price.

Including plant maintenance in the contracts

We propose that the slow-response reserve contracts allow for pre-agreed maintenance periods. Contract holders should notify TenneT well in advance of their intended maintenance schedules, and TenneT should have the ability to make adjustments (within limits) to the proposed schedule. This will enable TenneT to co-ordinate maintenance periods between contract holders. With the exception of the pre-agreed maintenance periods, power contracted for slow-response reserve would have to be available throughout the contract period.

An alternative arrangement might prohibit any maintenance periods. If contracted generators needed to perform maintenance, they could simply nominate a different plant to provide slow-response reserve during the maintenance period. If a smaller generator did not have an alternative plant, the generator could pay someone else to nominate their plant as a temporary substitute for the slow-response reserve contract. However, this arrangement would test the liquidity of the secondary market – which is uncertain – and would make the participation of smaller generators more difficult. We therefore do not recommend it.

5.2 Offer structure

TenneT should be responsible for conducting auctions for slow-response reserve contracts. Generators –and possibly load – will compete to win these contracts. One of the key issues to resolve is the form of the offer. There should be three key elements: the amount of capacity available for long-term balancing (MW); the price for making the

capacity available for a given period of time (€/MW/year); and the price for balancing energy when demanded (€/MWh). We discuss each of these in turn.

Quantity of capacity offered

The main issue to address is: should TenneT specify the capacity of the contracts offered, or should TenneT leave it to auction participants to decide how much capacity they wish to offer? For example, TenneT could specify a standard contract volume (for example, 100 MW), or auction participants could include the capacity of balancing power they want to supply as a dimension of their offer.

We see no reason for TenneT to specify the size of the contracts. TenneT will need to specify the total amount of capacity desired in the auction, but should let the market decide which generators supply how much capacity. This avoids the problem of specifying too much or too little capacity per generator. By insisting on excessively large contracts, TenneT might inadvertently discourage the participation of smaller generators. If the contracts are ‘too small’ then larger generators may not consider it worthwhile participating in the auction.

Instead of insisting on a particular amount of capacity per generator, TenneT could set a minimum and maximum size. A minimum offer size –for example 1% of the total capacity required – would avoid the need to arrange contracts with many small generators, with the attendant high transaction costs. A 1% limit would ensure that at most 100 generators could hold long-term contracts. We discuss a limit for the maximum level of capacity below.

A maximum offer limit and market structure

TenneT could impose a maximum offer limit in the auction, preventing any one generator from holding more than a specified percentage of the slow-response reserve capacity requested. A maximum offer limit could increase competition in the balancing market, by increasing the number of contract holders. However, if chosen incorrectly, a maximum offer limit could *reduce* competition in the long-term contract auction. For example, imagine an auction in which 100 units of a good are offered *for sale* to four strong participants.³⁵ The rules limit each bidder to no more than 20 units (*i.e.* a maximum bid limit of 20%). Each of the four participants would know that they could bid a very low price for 20 units, and the seller would have to accept the bid, because the other three strong participants together cannot take more than 60% of the total product. The maximum bid limit indirectly prevents competition among the four strong participants (in this example we assume that there are insufficient ‘weak’ bidders in the auction to worry the strong bidders). In effect, the maximum offer limit has inadvertently replicated the

³⁵ In auction terms, a strong participant is one that is likely to value the object being sold more highly than other participants, perhaps because the object offers synergies with other parts of the bidder’s business. For example, an oil field is worth more to a company that has a production platform next to the field, compared to a company that would have to build a new production platform especially to develop the field. In some cases, a bidder may be so strong that all other potential bidders decline to participate in the auction.

effect of a collusive agreement between the four strong bidders, splitting the market among them.³⁶

A maximum offer limit must account for the likely number of strong participants in an auction for slow-response contracts. There are currently five regular participants in the balancing market. However, the number of generators competing for slow-response contracts will be limited to those generators who own peak plants. Depending on the quantity of slow-response reserve that TenneT seeks, it may be efficient for one generator to win all of the reserve contracts. In section 4.4 we argue that it would be wise for TenneT to apply a cap to the energy offers of generators under long-term contract. This would limit the ability of generators to exercise market power in the balancing market and hence weaken one of the arguments in favour of a maximum offer limit.

In sum, the danger of setting a maximum offer limit too low – because of uncertainty over how many generators will participate in the auction – combined with an energy offer cap that mitigates market power in the balancing market, mean that *we do not recommend setting a maximum offer limit for the contract auctions.*

Even though a single generator might be able to supply all the reserve required, it is important that generators compete for the contracts. TenneT should therefore forbid generators from forming consortia that could reduce the number of strong auction participants.³⁷

5.3 Energy and capacity price offers

The relationship between capacity and energy price offers

In a competitive market, capacity prices should be inversely proportional to energy prices in the balancing market. The capacity payment pays generators their opportunity cost of ‘standing by’ in the reserve market. A plant with a low marginal cost would have a high opportunity cost in the reserve market, because it could have made relatively large profits in the day-ahead market. Therefore, the low-marginal-cost plant would require a larger capacity payment. However, the same plant would be able to offer energy at low prices. A converse relationship would hold for a plant with high marginal cost. The opportunity cost of such plant in the day-ahead market is low, so capacity payments could be low, but the energy offer price would be high.

³⁶ The discussion is not purely theoretical. In 2000, the Swiss auctioned off four mobile-phone licenses. There were only four bidders in the auction, and no one bidder was allowed more than one license – in effect a maximum bid limit. As a result each bidder was guaranteed to buy a license at the (very low) reserve price. This is a real world example of how maximum bid limits can be disastrous if applied incorrectly. For further discussion of this issue, see “What Really matters in auction design” Paul Klemperer August 2001. In the case of TenneT’s auction, a high price would be the anti-competitive outcome because participants are *selling* capacity rather than *buying* licenses.

³⁷ To avoid accusations of discrimination, TenneT may have to stop smaller generators from forming consortia, although there is no economic reason to do so.

Given the above, we would expect to see a range of offers, some with high capacity prices and low energy prices, and others with low capacity prices and high energy prices. Both could have a place in the balancing market.

Timing of energy and capacity offers

There are two main choices with respect to the *timing* of energy offers in the long-term balancing contract auction:

- Generators could make a two-part offer – that is, an energy offer at the same time as the capacity offer. TenneT would need to rank the two-part offers and award contracts.
- Generators could make a capacity-price offer only in the auction. TenneT would award contracts on the ranked capacity prices. Generators awarded long-term contracts would make energy-price offers on the day of despatch.

Two-part offers have the advantage of enabling TenneT to see all the price elements of an offer *before* contracts are awarded. Otherwise a generator may offer a low capacity price, but subsequently charge very high energy prices. Consequently, it might have been better to award a contract to a generator with a higher capacity price, who was offering balancing energy at lower prices.

However, there are at least four objections to the argument above. First, two-part offers introduce a complex ranking problem. Consider the choice between two offers: one has a high capacity price but low energy price, while the other has a low capacity price with a high energy price. An optimal choice depends on the likelihood of despatching the capacity. A high energy offer is less likely to be used, and so may be acceptable if the accompanying capacity offer is low enough. The TSO in England and Wales (NGC) awards reserve contracts using two-part offers, relying on a market model to predict the probability of despatch. However, using models reduces the transparency of decisions to accept some offers and not others, and invites challenges concerning the modelling assumptions and methodology. Other Market Operators in the U.S. have used simple formulae to rank two-part offers, but formulae are subject to gaming and abuse.³⁸

Second, it is not clear that generators would be able to charge high energy prices, once they had been given a long-term contract, because they would risk missing a profitable opportunity for despatch. The alleged ‘low-capacity price, high energy price’ problem implicitly assumes market power in the quarter-hourly energy auctions. In the absence of market power, generators will compete on energy price for profitable despatch. This view is supported in a paper by two economists, who argue that, if balancing energy offers are settled on a uniform price basis, TenneT can rank two-part

³⁸ For example, California’s 1993 reserve auctions used a simple linear scoring system to rank offers. Because the weighting given to the energy part of the offer was independent of the energy offer price, auction participants submitted offers with very large capacity payments and negative energy payments. The ranking of two-part reserve offers in England and Wales does not suffer from this problem, because the details of the model NGC uses to rank the offers are unknown, and therefore the ranking process is difficult to game.

offers on the capacity-price only with no inefficiency.³⁹ Even without vigorous competition, generators would be unable to charge unduly high prices because of the energy offer-caps we discuss in section 4.4.

Third, balancing prices could become more predictable if energy offers are fixed for the duration of the contracts. Predictable balancing prices could encourage market participants to ‘trade’ more power in real time, and hence may make the power system more difficult for TenneT to manage. Note that, even with fixed offers in England and Wales, predictable balancing prices are less of a problem because there are more generators.

Finally, making an energy offer up to several years in advance could impose large risks on generators. Some reserve markets in the U.S. use two-part offers, but over a much shorter time frame (typically day-ahead). The contracts we are considering will last for several years and so generators may be reluctant to commit to a specified offer price, because of fuel price risks. Indexation of the energy offers could help, but is not a perfect solution. We prefer allowing generators to make energy offers on the day.

We conclude that generators should submit capacity prices only at the time of the auction, and TenneT should award the contracts on the basis of these prices only. We describe the capacity auction in more detail in the next section.

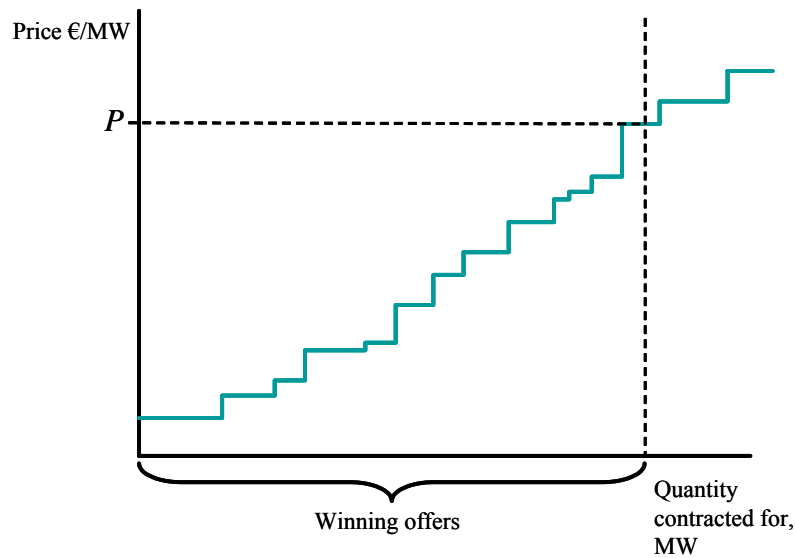
5.4 Auction format

Generators should submit sealed capacity-price offers to TenneT in a single round. Avoiding multiple rounds will reduce the chance of signalling and collusion between generators. TenneT should rank the offers on price. TenneT should then award contracts to generators in order of ascending capacity-price offer, until the required volume of contracts has been awarded (see Figure 9). However, TenneT then faces a choice concerning the rules for paying successful auction participants. TenneT could pay the same price (€/MW/year) to all the generators awarded a contract, set at the level of the highest accepted offer (price P in Figure 9). This is called a uniform-price auction. Alternatively, TenneT could pay winning generators their capacity-price offer. This is called a pay-as-offer auction.⁴⁰

³⁹ See “Multi-Dimensional Procurement Auctions for Power Reserves: Robust Incentive Compatible Scoring and Settlement Rules” Hung-Po Chao and Robert Wilson, *Journal of Regulatory Economics*; 22:2 161-183, 2002.

⁴⁰ This type of auction is also known as a discriminatory auction, because the auctioneer discriminates between participants in the price they receive.

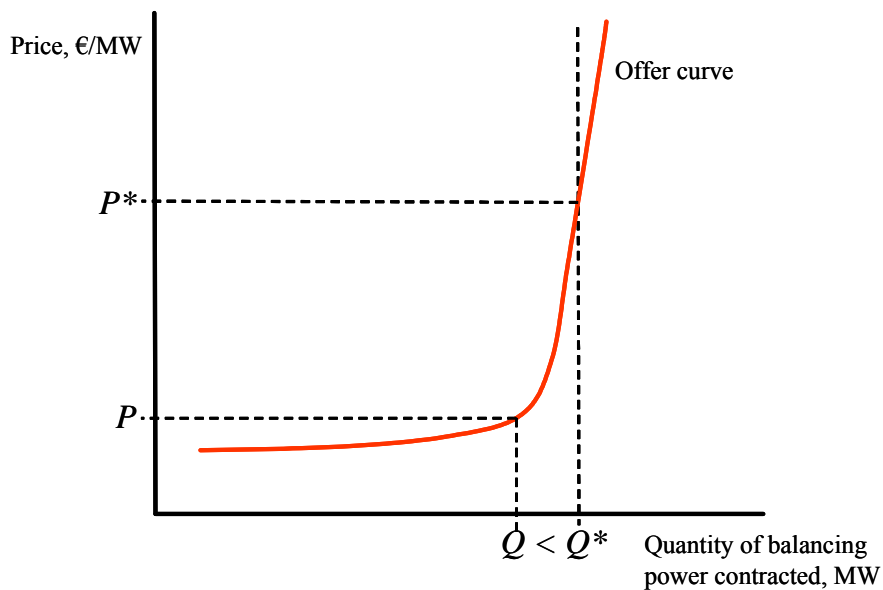
Figure 9: Example ranking of capacity offers



Some economists argue that a uniform-price auction is more susceptible to tacit collusion.⁴¹ Auction participants can use infra-marginal offers (*i.e.* offers that will be accepted, because they are below the clearing price) as a costless threat to maintain a collusive market share. For example, imagine a uniform price auction for long-term balancing contracts with four participants. Each participant offers to supply somewhat less than their collusive share (in this example, 25% of the total) of the requested power at a very low price, but the offer-price rises sharply around the collusive share (represented by Q^* in Figure 10). If all the participants stick to their collusive shares, they will each receive the relatively high price P^* in the auction. However, if one of the participants attempts to win more than Q^* so that the other participants only win contracts for Q MW, the price will collapse to P . Each participant is using the low offers to the left of Q^* as a threat to the other auction participants; if they break the collusive agreement, they will be punished by low prices. The equilibrium outcome is that all participants stick to the collusive share. The threat of low prices is costless in equilibrium, because the auction is uniform price. Each participant receives P^* for all the capacity offered.

⁴¹ See “What really matters in auction design” Paul Klemperer August 2001, page 4 for more discussion of how uniform price auctions can support collusive outcomes. We also note that there is some disagreement in the literature regarding how much the uniform price format contributes to collusion, and how much the frequency of auctions contributes.

Figure 10: Example of collusive offer curve in a uniform price auction



The argument that uniform price auctions can support collusive outcomes leads us to consider a pay-as-offer auction. However, a pay-as-offer auction has the very significant disadvantage that auction participants must have much more information to participate successfully in the auction. In the uniform price auction, participants can simply offer balancing capacity at their opportunity cost. This is a profit maximising strategy, because auctions participants will receive a capacity payment based on the opportunity cost of the highest accepted offer. In a pay-as-offer auction, participants who offer capacity at their opportunity cost would make zero profit. To maximise their profits, each participant must estimate the opportunity cost of the all other auction participants, and offer just below the highest offer likely to be accepted. To estimate the opportunity cost of all other participants requires significant information about competitors and the market.⁴² Moreover, this it is something that large generators are much more likely to be able to do, because they have more information about the market and greater resources to expend on the problem. Smaller generators will be disadvantaged and could be put off from participating in the auction altogether.⁴³ As one of our objectives is to encourage as much participation in the auction as possible, this problem, in itself, is sufficient to rule out use of a pay-as-offered auction format.

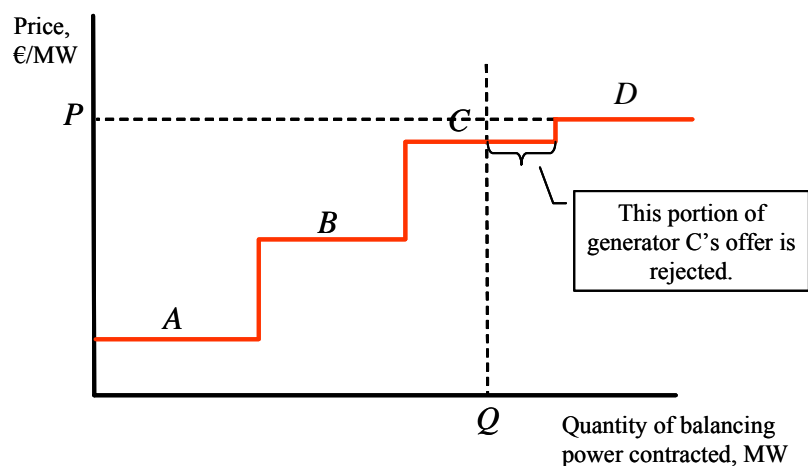
Moreover, we can overcome the main disadvantage of the uniform price auction – that it can sustain collusive outcomes – if we restrict the form of the offers. Several economists have demonstrated that restricting auction participants to a finite number of price-quantity offers – rather than allowing a continuum of offers in the form of a curve –

⁴² See Persico, Nicola. 2000 “Information Acquisition in Auctions” *Econometrica*, 68:1, pp. 135-48.

⁴³ Paul Klemperer, the well known economist and auction theorist, notes that “pay-your-bid...auctions may discourage potential bidders who have only small amounts to trade and for whom the cost of obtaining market information might not be worth paying” (see footnote 41 for reference).

solves the collusion problem illustrated in Figure 10.⁴⁴ The reason is that the modified offer curve creates competition for marginal units. Consider again the example of an auction for balancing contracts with four participants, labelled A, B, C and D in Figure 11. Participants are only allowed a single price-quantity offer, so that the combined offer schedule is a series of steps (see Figure 11). In the previous situation with a continuous offer schedule (in effect, an infinite number of price-quantity offers) any attempt by an auction participant to increase its share of contracts would result in a sharp price decrease. With the offer formats in Figure 11, participants can realise a very large increase in contracts award with only a relatively small decrease in their offer price, and in the resulting market clearing price. For example, Generator D has only to decrease his offer slightly to displace Generator C completely. Restricting the number of price-quantity offers each generator can make creates more competition in the auction, which will result in lower capacity prices.

Figure 11: Uniform price auction with restricted offers



Marginal quantity offers, such as Generator C's offer above, will be reduced to fit the available quantity. In the event that two or more generators have marginal offers at exactly the price, the available capacity should be awarded to these bidders in proportion to their offers. The absence of a restriction on the format of offers should minimise the chance of two identical price-offers.⁴⁵

⁴⁴ For example Kremer and Nyborg illustrate how imposing restrictions on the number of price-quantity offers can eliminate underpricing – where an item is sold for less than the buyers value the item. See “Underpricing and Market Power in Uniform Price Auctions”, I.Kremer and K.Nyborg, *Review of Financial Studies*, forthcoming. The paper by Fabra, N. , N-H von der Fehr and D.Harbord 2002 “Designing Electricity Auctions” , *The Electricity Journal* makes a similar point.

⁴⁵ TenneT could require that offers are made to the nearest Euro, but there is no need to restrict offers to e.g. the nearest 1,000 Euros. To do so increases the chance of two identical and marginal offers, and could lead to inefficient offers. For example, where a generators cost-based offer lies between two allowed offers, he will be forced to chose the highest offer, rather than offer at below cost.

Vickrey auction vs. uniform price

A Vickrey auction is a variant of a uniform price auction. In a Vickrey auction, the clearing price is set by the lowest *rejected* offer, not the highest accepted offer.⁴⁶ The advantage of the Vickrey auction format is that it encourages participants to offer at a price closer to their actual cost. In contrast, participants in a uniform price auction may worry that their offer will be marginal. If it is, they will make zero profit by offering at their actual costs. Therefore, they may add on a small margin to allow for the possibility that their offer could be the marginal, price setting offer. This is more likely in an auction with relatively few participants. With a Vickrey auction participants need not do this, because the lowest rejected offer will set the price. The Vickrey auction therefore has some efficiency advantages, in that the generators with the lowest costs are more likely to be awarded the contracts.

However, with a Vickrey auction there is also a risk that an offer from an expensive generator could set the price. The winning generators could get a price far in excess of what they required to recover their costs.⁴⁷ Such an outcome is particularly likely when there are large differences between auction participants, both in terms of costs, information and sophistication. In the auction of long-term slow-response reserve contracts, it is likely that some small generators will make offers. These offers could be at far higher levels than those of the larger generators, either because the smaller generator has highest costs or because he has made an error in judging an appropriate offer level. If such an offer set the price, this would result in very expensive contracts.

Because we wish to encourage a wide range of auction participants, the potential efficiency benefits of a Vickrey auction are outweighed by the risk of a small, erroneous offer setting the price for all the contracts. Accordingly, we do not recommend the use of a Vickrey style auction for allocating TenneT's long-term reserve contracts.

How many price-quantity offers should TenneT allow?

We have proposed that generators will *ex ante* have to specify which of their plants are providing slow-response reserve, for verification purposes. However, we are not suggesting that each offer has to be limited to a single plant or that the same plant has to provide the slow-response reserve all of the time. It is only once an offer has been accepted, generators will have to specify the plants with which they will provide slow-response reserve.

⁴⁶ The intention of the Vickrey auction is to mimic the outcome of an open outcry, ascending price auction, the format used by large auction houses. In such auctions, the bidding stops when there is only one participant left. The last bidder to drop out of the auction sets the price of the object.

⁴⁷ New Zealand's mobile spectrum auction provides a notorious example of where a Vickrey auction delivered an unsatisfactory outcome. There were only two bidders for a single license; the winner bid NZ \$ 7 million but paid only the price of the *rejected* bid – which was NZ \$ 5,000. The case illustrates the important relationship between auction design and the number and type of auction participants.

If generators were only allowed a single price-quantity offer, they would have to make their offer based on the *average* costs of the plants that will actually provide reserve power. If the offer was rejected in the auction, because it was too expensive, this could be inefficient. The generator may wish to re-submit an offer for a smaller quantity of power, based on the cheaper plants in its portfolio. Therefore, if generators are allowed only a single offer, a multiple round auction may be required for an efficient outcome. However, multiple-round auctions are undesirable, because they enable participants to signal to one another and this facilitates collusion. Our preferred solution is to allow auction participants to submit two price-quantity offers. This will avoid the need for a multiple round auction, enable participants to submit offers that reflect the opportunity costs of the underlying plants more accurately, and reduce the possibility of collusion by prohibiting a continuous schedule of offers. Other uniform price auctions use similar restrictions on offers.⁴⁸

Summary of the auction format

We recommend that TenneT should purchase slow-response reserve via a uniform price auction, with all successful participants paid the capacity-price of the highest offer accepted in the auction. The auction should have a single round, with participants restricted to making two separate price-quantity offers. Equal, marginal offers from different generators should be allocated on a pro-rata basis.

5.5 Contingency planning for the auction

While we have tried to design an auction that will attract participants, avoid the exercise of market power and deliver competitively-priced capacity contracts, there is always the risk that, for whatever reason, the auction does not achieve these objectives. In this section we discuss what TenneT can do if such a scenario materialises.

The main objective of the auction, and therefore the criterion on which it should be judged, is that the price determined for the long-term supply of slow-response reserve represents value for money. If, after the auction, it appears that the resulting price does not represent value for money, the auction can be considered a failure. TenneT should take a number of steps in anticipation of such an event.

First, TenneT should advertise in advance that it reserves the right not to award any long-term contracts on the basis of the auction results, if it judges the resulting capacity price to be ‘unreasonable’. TenneT should not advertise a maximum acceptable price before the auction, because this could facilitate the exercise of market power. For example, suppose TenneT published a reasonably high maximum price. If market power is present, generators will know they can offer just below the maximum price and still have their offer accepted. In contrast, if generators are uncertain about the maximum acceptable price, even if they have market power they may moderate their offer prices to ensure that their price offer is ‘reasonable’ and therefore acceptable. Similarly,

⁴⁸ For example, participants in auctions for Italian treasury bonds are restricted to three price-quantity bids each.

advertising a maximum price that is actually ‘too low’ (*i.e.* below the actual costs of many generators) will put generators off from participating in the auction, and condemn the auction to failure. TenneT can avoid such problems by not specifying a maximum price.

TenneT should insist that all offers made in the auction must be valid for at least one month. Following the auction, TenneT should reserve the right to investigate, within that month, the reasonableness of the resulting price. This investigation should be conducted with the assistance and oversight of DTe. TenneT and DTe could base the test of reasonableness on a number of factors, such as the estimated costs for generators and prices for capacity in other markets.⁴⁹ If the investigation determines that the auction price was unreasonable, TenneT will declare the auction results void. TenneT and DTe should then publish a report describing why they believe that the price reached in the auction is unreasonable, and how they reached their conclusions. This will provide assurance to the market that any voiding of the auction results was not an arbitrary action by TenneT, but was based on sound reasoning subject to public scrutiny.

If TenneT does void the auction results, then, in the absence of market structure changes, there is little reason to believe that another auction would yield any better results. Therefore, TenneT’s best fall-back option is to conduct bilateral negotiations with generators for the supply of slow-response reserve. However, bilateral negotiations are more likely to be subject to market power, and less likely to result in a cost-reflective price. (This is why TenneT wanted to avoid such negotiations in the first place.) If generators know that holding bilateral negotiations are TenneT’s fall-back option, they may try and sabotage the auction to help bring these negotiations about. Therefore, TenneT should advertise that, if it does sign bilateral contracts for slow-response reserve, it will do so with at most *two* generators, and these generators will be forbidden from selling all or part of the contracts in a secondary market. Assuming that there are more than two generators who would like to sell slow-response reserve to TenneT, this strategy should reduce the attractiveness of bilateral negotiations for generators. For example, if there are four generators who would like to sell slow-response reserve to TenneT, but TenneT will only sign contracts with two of them, all the generators will worry that they may be left without a contract.⁵⁰ TenneT should also state that any generator failing to enter into good-faith negotiations for the supply of slow-response reserve could be subject to an investigation by NMa.

⁴⁹ For example, the capacity price for standing reserve in England and Wales was about 40000 €/MW/year for the contracting period 01/04/03 to 01/04/04 (Source: National Grid Standing Reserve Market Report Tender Round for Standing Reserve Service from BM and Non BM providers for Contracts Effective from 1st April 2003 to 1st April 2004). Prices much above this should give TenneT/DTe cause for concern.

⁵⁰ It is important that TenneT sign contracts with less generators than can actually provide slow-response reserve cheaply, so that at least one generator will be ‘left out’. As we are not certain how many generators can offer cheap slow-response reserve, we sat TenneT should sign with at most two generators. Negotiating with one generator only would risk market power abuse.

Another possibility is that the auction may elicit offers for less capacity than TenneT requires. For example, TenneT may be seeking contracts for 500 MW of capacity, but only receive offers for 300 MW. As long as the price determined by the auction satisfies the reasonableness test, TenneT should issue contracts for the reserve offered in the auction. Depending on the level of the shortfall and the position of the DTe, TenneT could either decide to do nothing or to seek additional slow-reserve contracts by negotiating bilaterally with generators, in the manner described above. TenneT would have the advantage that the auction has already established a price for slow-response reserve, and could use this price as a starting point in the negotiations.

5.6 A secondary market for long-term balancing contracts

A secondary market for long-term contracts would enable generators to sell contracts awarded in the auction. This would have two main benefits. First, it would encourage generators to participate in the auction, because they would know that they can easily sell the contracts in the secondary market if their circumstances change. Otherwise, generators may be unwilling to sign long-term contracts for larger amounts of capacity, in case they want to sell the plant that provides the balancing power. For example, it would enable generators to tailor the length of the contracts. Without a secondary market, TenneT will have to try to ‘guess’ what the market wants by offering contracts of various lengths. With a secondary market, generators who want a one-year contract can simply buy a three-year contract and sell it after a year.

Second, a liquid secondary market, with published clearing prices, would provide an ongoing signal as to the value of capacity. This could aid efficient investment and retirement decisions.

Trading in long-term contracts

A slow-response reserve contract would pay a fixed amount per MW for making energy offers in the balancing market. This fixed payment is the ‘face value’ of the contract. The *sale value* of the contract to a generator is the face value of the contract, minus the cost of holding the contract. For example, if a contract had a face value of 15,000 €/MW/year, and a generator’s cost of providing 1 MW of slow-response reserve was 10,000 €/MW/year,⁵¹ the generator would be willing to pay up to 5,000 €/MW/year for the contract. The sale value of the contract would be 5,000 €/MW/year. If the market is efficient, the generator with the lowest costs should buy the contract, because it will have the highest sale value. Differences in the cost of providing slow-response reserve, both over time and between generators, would drive contract trading in the secondary market. The market value of the contracts would allow market participants to derive the expected profits from a MW of peak-power in the market.

⁵¹ The generator’s cost of providing slow-response reserve is the fixed costs of the plant that provides the reserve. The generator could avoid these costs, if the plant were retired.

Establishing a secondary market

It is important that a trading platform for long-term contracts is established and ready-to-go, *before* the initial auction for long-term contracts takes place. The existence of a trading platform will provide reassurance to potential auction participants that they easily dispose of any long-term contracts they sign. This, in turn, will encourage participation in the auction, since generators should be more willing to enter into an agreement out of which they can easily get.

It is possible that a secondary market for long-term contracts would arise naturally but this could take some time, and one may not have developed at the point that generators must decide whether to participate in the auction. Moreover, the market could be an Over-The-Counter (OTC) style market, where prices are not necessarily quoted publicly. This would mean that one of the main benefits of a secondary market would be lost – namely, that it would provide an ongoing price of capacity that can be used for investment decisions.

We recommend that TenneT and/or the Ministry take an active role in establishing the secondary market, in parallel with organising the auction of long-term reserve contracts. TenneT could delegate the running of the secondary market to another organisation, for example the APX. However, TenneT should insist on certain rules, for example that the market operate must quote publish prices, and inform TenneT of trades. TenneT could also specify in the long-term contracts that they can only be traded on the ‘official’ secondary market endorsed by TenneT. This would help concentrate liquidity in trading of long-term contracts, and generate a more reliable price signal.

Organising trading in the secondary market

We recommend that TenneT makes the long-term contracts ‘divisible’. In other words, if a generator is awarded a 100 MW contract in the original auction, then some fraction *e.g.* 10 MW, can be sold to another generator. Divisible contracts will make the secondary market much more liquid. The minimum capacity limit that applies in the auction would apply in the secondary market. For example, assuming a 1% limit on the minimum size of capacity offer, and that TenneT contracted for 500 MW of balancing power, 5 MW would be the smallest trade that could take place. TenneT would need to track trades of long-term balancing power, and monitor each generator’s contractual obligations in the balancing market.

The secondary market would not need to be elaborate or complex. In essence, it would be little more than a ‘bulletin board’, where holders of reserve contracts can advertise that they wish to sell a contract, or generators without a reserve contract can ask to buy one. However, we do recommend some basic features to encourage fair trading. For example, we recommend that buyers and sellers remain anonymous to one another until after the price for the contract has been agreed. This would prevent a dominant generator from ‘shopping around’ other generators and using this knowledge to trade in a discriminatory fashion. After a trade is agreed, the price and quantity would be published on the bulletin board and the buyer and seller’s identity would be revealed to one another

(although not to the market at large). The buyer and seller would then settle the trade directly; no ‘market maker’ or clearing party would be required.

Generators who buy a contract may worry about the credit worthiness of the generator selling the contract, if this generator is responsible for passing on the capacity payments it receives from TenneT. One solution is that TenneT always makes capacity payments directly to the current holder of the contract, rather than letting the original contract holder pass on payments. This would overcome credit fears, facilitate trading and make the secondary contract market more liquid.

Market power in the secondary market

It is possible that, initially at least, there may be only one seller of contracts in the secondary market. However, we are not concerned about the possibility of market power in the secondary market. This is because market power is only a problem if the traded good is an input to another product. For example, exercising market power in a market for pipeline capacity is a concern, because pipeline capacity is required for selling gas to end-customers. Withholding the pipeline capacity could allow a market player to raise final gas prices and make excessive profits. However, if a generator attempts to raise the price of a slow-response reserve contract above what other generators are willing to pay, then no trade will take place, and the original generator will continue to hold the contract. Moreover, a generator would have no incentive to withhold contracts from the secondary market, if he could sell these contracts in the secondary market at a profit. Therefore, while we would like trades to take place (because trades generate capacity prices which are a useful indicator for the market) there are no inefficiencies that result from a failure to trade. If a generator finds it profitable to sell a contract, it will do so.

6 Auction quantities and frequency

TenneT could decide to auction a small quantity of long-term contracts on a frequent basis, or a large quantity of contracts infrequently. We propose that it should hold infrequent auctions for a large amount of capacity, because this will reduce the risk of collusion for two reasons.

First, frequent auctions make collusion easier. Auction participants learn each other's behaviour, and have a chance to 'punish' fellow participants – by, for example, raising the prices of contracts to very high levels – if they deviate from collusive strategies.⁵² In contrast, holding the auction for long-term contracts infrequently, say once every three years, would make collusion more difficult. If the period between auctions is long enough, it is difficult for auction participants to apply experience of other participants' behaviour in the previous auction to the current auction, because several important factors (costs, market structure *etc.*) may have changed in the intervening time. Infrequent auctions also reduce the effectiveness of 'punishment' for breaking the collusive bargains in future auctions. Any reduced profits as a result of the punishment take place far in the future, and are discounted. Consequently, collusion is more difficult to sustain in less frequent auctions.

Second, increasing the value of the contracts being auctioned – by offering larger amounts of capacity at a time or the same amount of capacity for a longer time – makes collusion more difficult to sustain. If the contracts to be won are large and reasonably profitable, there will be more temptation to cheat on any collusive agreements. For example, consider a case where five strong auction participants agree that one of them will not participate in the auction. The remaining four offer to supply 25% of the long-term balancing auctioned at very high prices, in the knowledge that they will achieve this high price because there are only four strong participants participating in the auction. The four participants agree *ex ante*, to sell some of their highly profitable long-term balancing contracts to the generator who agreed to stay out of the auction, at a pre-agreed low price. However, if the contracts are large and therefore very profitable, the four generators who participated in the auction have a strong incentive to renege on the collusive agreement *ex post*, and keep the contracts for themselves.⁵³ The generator who would potentially stay out of the auction knows this, and therefore refuses to stay out of the auction in the first

⁵² For example, Natalia Fabra in her 2003 paper, Tacit Collusion in Repeated Auctions: Uniform Versus Discriminatory, *Journal of Industrial Economics* Vol 51, Number 3, pp 271-293, says that “[b]oth theory and practice suggest that collusion is a particularly critical issue when auctions are repeated frequently. In a dynamic setting, bidders may learn to coordinate their strategies, and hence compete less aggressively with each other in order to raise profits over the level that would be attained in a static setting.”

⁵³ The generators could also sell the valuable contracts on the secondary market for a profit. The secondary market makes collusion even less stable, as the auction participants have a clear alternative to selling to the fifth generator at a discounted price, assuming they do not want to keep the contracts themselves.

place. The high value of the contracts makes the collusive agreement unstable, and so competition in the auction results.⁵⁴

If TenneT holds infrequent auctions for large amounts of capacity, there should be no need for a cap on the maximum offer price for capacity. As the example above illustrates, collusive agreements will be unstable, and competition should result. Moreover, there is a risk that TenneT could set the price cap too low, which would put off generators from participating in the auction. It is better to rely on a well designed auction than apply price caps. In light of the argument above, *we recommend auctioning the entire quantity of long-term balancing contracts required in one auction.*

6.1 The role of ‘future’ and ‘current’ balancing contracts

Long-term balancing contracts carry an obligation to offer power on the balancing market. Up to this point, we have assumed that this obligation starts soon after TenneT awards the contracts. However, it would be advantageous to offer a second class of long-term contract, where the obligation to offer power in the balancing market – and the associated capacity payments – start several years after TenneT awards the contract. We call these ‘future’ long-term contracts. Future contracts could help finance new power plant construction, by giving the project a guaranteed stream of income from capacity payments at the beginning of the project. A future contract could also help to defer the retirement of existing plant, scheduled for retirement in several years time. For future contracts to be effective in motivating new investment, the obligation to provide balancing power should start at least three years after the date of contract award. This should give sufficient time for project developers to build the power plant, following contract award.

There is a risk that the promised power plant will fail to materialise. In this event, TenneT would not pay any capacity fees, and would include the non-existent reserve offer from the future contract holder at 0 €/MWh in the bid ladder. When the capacity is ‘called’, clearly it would fail to despatch. The contract holder would be out of balance, and the next most expensive offer would be called. The contract holder would be liable to settle the imbalance at the resulting balancing price.

To avoid this scenario, the contract holder could sell the future contract in the secondary market. The ability to sell the future contract, if the project fails, will encourage the developer to buy the future contract in the first place. It provides a useful source of potential income that makes the project more attractive to lenders, and the developer can sell the future contract if things do not work out as planned.

⁵⁴ The commercial jet aircraft market provides further evidence of how high-value contracts increase competition and suppress collusion. Only two players – Airbus and Boeing – dominate this market. However, the commercial jet business is highly competitive. The reason is that jet supply contracts are usually for large sums of money, and are valuable over many years. Any attempt of Boeing and Airbus to divide the market – perhaps by winning alternate contracts – would be hard to sustain because it would be very profitable for one of them to cheat on the agreement and win a large contract ‘out of turn’.

The contract mechanism and new-build

Throughout this report, we have generally emphasised the need for the new contract mechanism to *defer* the retirement of peak plant, as opposed to building new peak plant. This is because, when the contracts are first introduced, deferring plant retirements (perhaps by making some small investment in the plant) will be the cheapest way of providing slow-response reserve.

This does *not* mean that the new contract mechanism cannot support new build. Over time, peak demand may grow. For example, more air conditioning could increase peak demand, which will be reflected in higher peak prices. As a result, new peak plant will be required. The contract mechanism will be able to cope with such developments because it is a *market-based mechanism*. Offers from auction participants set the price of the slow-response reserve contracts. As the cost of providing slow-response reserve increases over time (because peak prices are increasing so the opportunity cost of providing slow-response increases) so the price of slow-response reserve contracts will increase. Eventually, the price of slow-response reserve will increase to a level that can support new peak plant construction, if this is required.

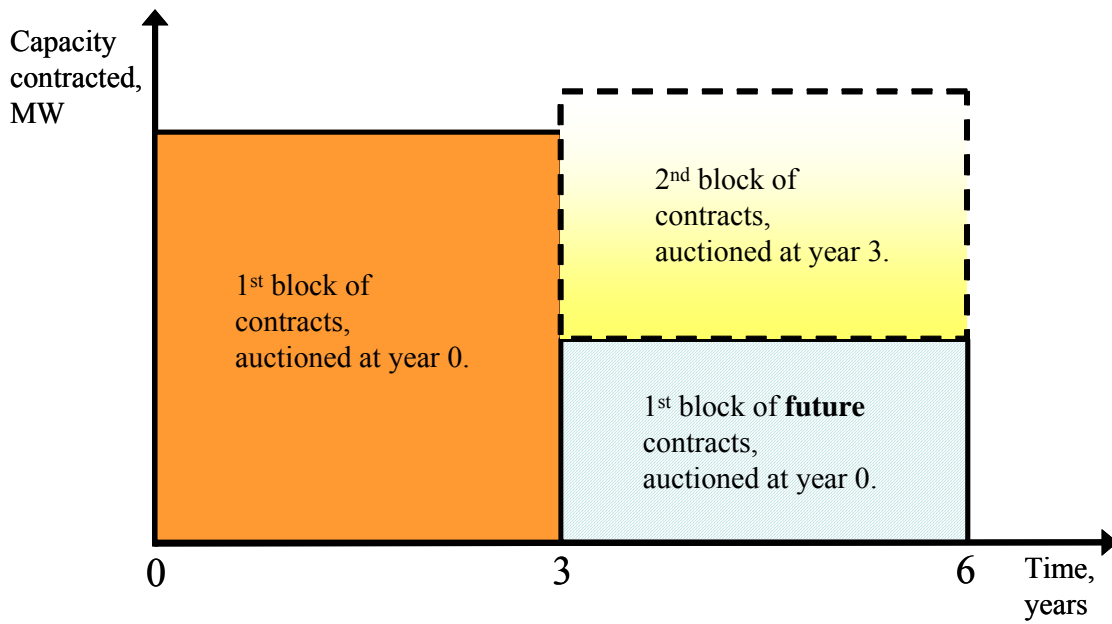
6.2 The length of the balancing contracts

As we argue above, balancing contracts should be of a substantial length, because this will increase their value, make auctions less frequent and therefore make collusion more difficult to sustain. However, generators may be reluctant to enter into very long-term contracts, especially in the first round of auctions when the liquidity of the secondary market is unproven. We must also consider the fit between the future and current balancing contracts. If the contracting periods of these two products overlap, an excess of contracted capacity could result.

We propose to schedule the auctions as in Figure 12. TenneT would auction both current and future contracts at year 0. Current contracts would have obligations to offer capacity almost immediately after the auction. To avoid contracting an excess of balancing power, the current contracts would expire when obligations under the future contracts start (in year 3). The future contracts, issued in year 0, would also have a duration of three years. A three year contract would allow any new plant to weather a cyclical downturn in power prices. This would provide comfort to plant developers, who may be concerned that, at the time of plant commissioning, prices are unusually low. TenneT would hold a second auction for current long-term contracts in year 3, to ‘top-up’ the difference between required long-term balancing power and the balancing power contracted with the future contracts.

The quantity of future contracts auctioned in year 0 should be substantially smaller than the total anticipated requirement for long-term balancing capacity in years 3 to 6. This would avoid over-contracting for balancing power in years 3-6, if the realised need for balancing was less than anticipated. It would also mean that the auction of new current contracts in year 3 would be for a sizeable capacity, which is more likely to attract auction participants. If TenneT sold a larger amount of future contracts in year 0, only a small sale of current contracts might be required in year 3.

Figure 12: Proposed auction schedule



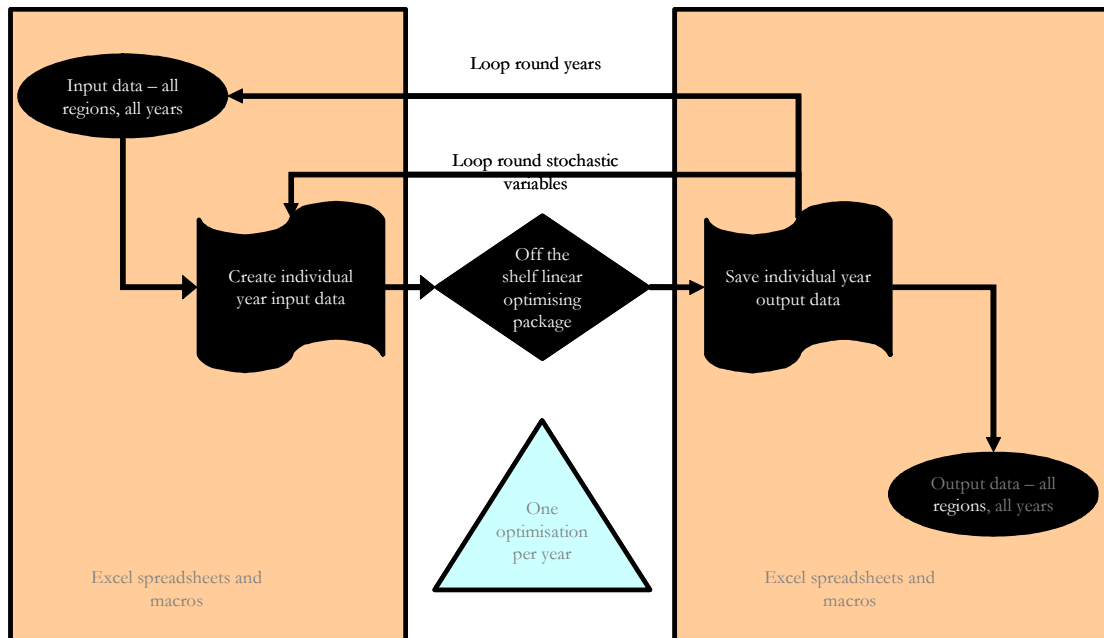
The duration of the second ‘batch’ of current long-term balancing contracts could be longer than the first batch, because the secondary market for long-term contracts should be well established at this point. Consequently, generators would be more willing to sign longer term contracts, in the knowledge that they can easily sell them on a liquid secondary market.

Appendix I : Model details and assumptions

Description of the Brattle Annual Model

At the heart of BAM is a cost-minimising plant scheduler that, in conjunction with a sophisticated fixed-cost recovery module, enables marginal costs and prices for any number of interconnected countries (or regions) to be modelled. The model can be run in two modes: (a) fast – deterministic runs with simplified approaches to forced outages, to demand variations and to wind output patterns to provide initial indications of prices or to model longer periods and (b) detailed – stochastic representation of these variables using a random number generator to give a more detailed insight into prices and their volatility but taking longer to run. This is illustrated in Figure 13.

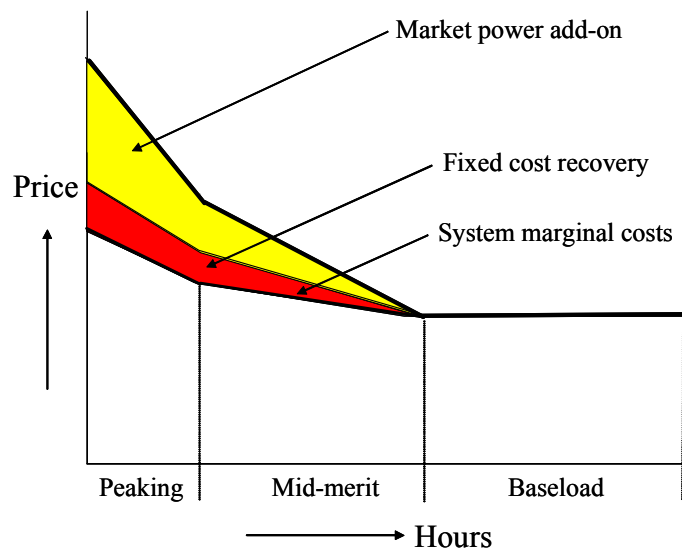
Figure 13: Outline of model structure



Pricing methodology

While cost-based scheduling is a well-established method of estimating short-run marginal costs (SRMC) for an electricity system, SRMCs do not necessarily reflect prevailing market prices. With excess capacity, SRMC prices would not enable existing plant, particularly peaking plant to recover their fixed costs. In addition, the actions of dominant generators may also affect prices. Our model allows the addition of “uplifts” to SRMCs to enable typical peaking, mid-merit and running plant to recover their fixed costs as well as their variable (short-run) costs. Figure 14 illustrates this schematically.

Figure 14: Schematic of pricing methodology



The hourly SRMCs produced by the scheduler are sorted into descending price order and the revenues that a typical peaking plant would earn estimated. For example, if the user expects a peaking plant to operate at a load factor of around 10%, then the model will assume that the plant captures the top 10% of prices (although a failure to completely capture the top prices can be incorporated via a “degradation factor”). These revenues are then compared with the costs of a peaking plant and prices are increased until it can just cover its fixed and variable costs. The price increases are structured so that the highest increases are applied to the highest SRMCs – in effect they are added on in a triangular fashion.

Once the calculations have been completed for the peaking plant, the same approach is taken for the mid-merit plant, taking into account the price increases applied to the peak prices. This prevents mid-merit plant earning excessive profits. Finally, the process is repeated for the running plant. All the parameters used in these calculations are under the control of the user, including the extent to which fixed cost recovery is allowed.

In addition to allowing the recovery of fixed costs, the model also allows market power add-ons to be incorporated, again with separate add-ons possible for the peaking, mid-merit and running sections of the market. These market-power add-ons can be negative as well as positive, to allow predatory pricing practices to be captured. Appropriate market power add-ons can be determined by calibrating the model against historic market prices and forward curves.

While this approach to market power changes prices, it will not affect generation schedules, e.g. a company giving up market share in order to increase prices. This type of behaviour can be captured by allowing the offer prices used in the schedulers to deviate from marginal generating costs or by applying the mark-ups calculated for each hour in a market to be applied to all plant in the market. Both approaches enable the flows between countries to reflect prices rather than costs and hence to replicate historical flows.

Model inputs

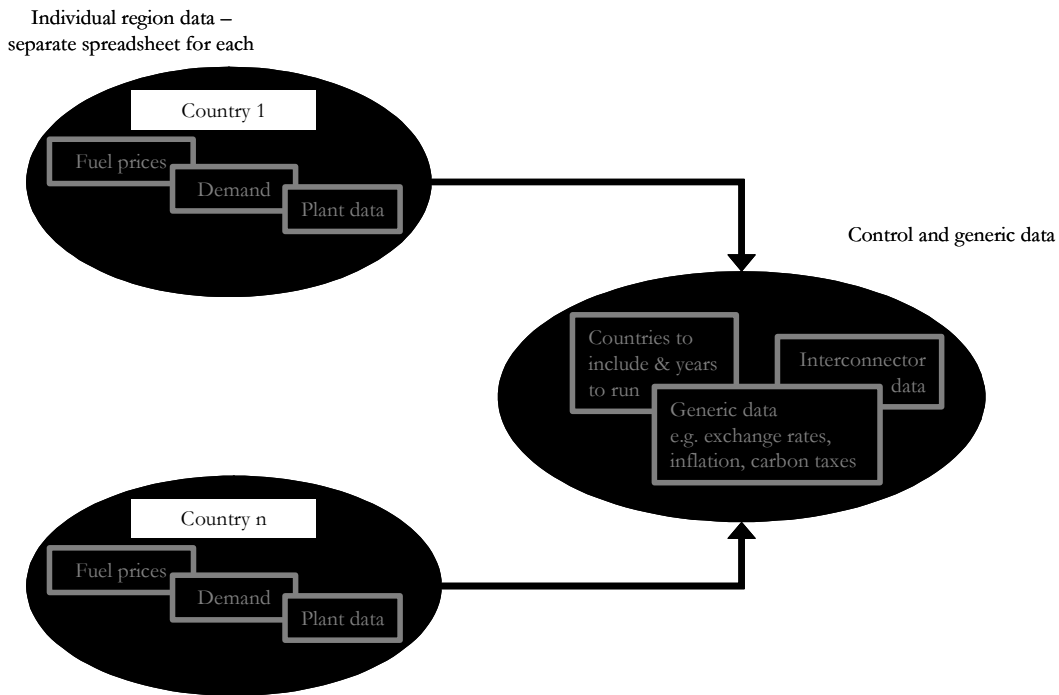
The generic types of required input data include

- Fuel prices: generic international prices for coal and oil products and country specific domestic fuel prices; including gas contract prices⁵⁵, and taxes;
- Fuel characteristics: calorific values, carbon, sulphur and nitrogen content;
- Current plant capacities, retirement of existing plant and entry of new capacity, including renewables;
- Other plant characteristics (fuel blending requirements, maintenance requirements, environmental measures e.g. flue gas desulphurisation levels, forced outage levels, thermal efficiency etc.);
- Plant costs: fuel transport costs, non-fuel variable costs (e.g. coal milling costs, variable O&M costs, market power uplifts etc.), fixed costs; transmission loss factors;
- Electricity demand profiles and growth;
- Contractual arrangements (physical bilateral contracts, must-take fuel contracts);
- Environmental constraints and costs: plant and country/regional emissions limits and costs,
- Financial parameters: exchange rates and inflation rates;
- Inter-regional data: monthly capacities in both directions, losses etc;

These data are required for each country (or region within a country where market splitting occurs) to be included within the model. The model can accommodate varying numbers of countries, with all the data specific to a particular country grouped into an individual Excel spreadsheet. Generic and control data are held in a separate spreadsheet, as shown in Figure 15.

⁵⁵ In addition to allowing gas contract prices to be linked to other fuel prices and inflation, it will be possible to include indexation to the previous year's electricity prices.

Figure 15: Data structure



The model utilises a characteristic day representation of demand with 3 characteristic days for each month (weekday, Saturday, Sunday) being used to represent the demand over a year. Since the countries modelled will have electrical connections to other countries, it is important to incorporate the impact of flows into and out of the model area. The model can incorporate historical net flows from each surrounding country as zero-priced flows, which effectively forces these to take place, using UCTE data. However, the model structure allows any number of import and export flows to be incorporated (with separate volumes and prices for each flow for each month and distinguished between day and night). Thus, a simplified step-wise approximation to the marginal cost curve in a country can be used to define several tranches of import (or export) flows. Whilst this method is more flexible, it effectively requires modelling the surrounding countries (at least to some extent) in order to produce an appropriate marginal cost curve. It is for this reason that we suggest using a simpler approach initially.

Outputs other than prices

In addition to detailed price data, the model also produces information on the output, revenues and costs of each generating plant, the flows across interconnectors (both within the model area and to countries outside it), fuel consumption and emissions levels.

Main modelling assumptions

Rather than just modelling the Netherlands in isolation, we used a detailed (plant-by-plant) representation of north-west Europe (the Netherlands, Germany, Belgium, France and the UK) together with less detailed representation of the main connecting electricity markets (NordPool, Poland, Czech Republic, Austria, Switzerland, Italy and Iberia). Plant

data were obtained from a variety of published sources and from a proprietary dataset produced by Utilities Data Institute.

Wherever possible, the fuel price assumptions that we used were based on current forward curves. Beyond the end of the forward curve, we held prices constant at the last forward price. For gas prices in the Netherlands, we estimated a contracted gas price based on the Gasunie oil-linked formula. Similar oil-linked gas prices were used in continental Europe. Table 10 summarises the assumptions. In addition, carbon costs of 31 €/tCO₂ in 2005, 36 €/t CO₂ in 2006 and 40 €/tCO₂ thereafter were included in the marginal costs of all generators.

Table 10: Fuel and exchange rate assumptions

	LSFO (\$/t)	HSFO (\$/t)	NBP (p/th)	Gasunie (€/MBtu)	Coal (\$/t)	\$/€	£/€
2005	164.5	156.6	24.8	2.90	56.3	1.38	0.67
2006	158.5	151.1	24.7	2.87	44.5	1.30	0.68
2007	156.0	148.7	24.0	2.92	35.5	1.25	0.68
2008	153.6	146.5	24.0	2.95	35.0	1.23	0.69
2009	153.2	146.1	24.0	2.93	35.0	1.23	0.69
2010	153.3	146.2	24.0	2.93	35.0	1.23	0.69

We calibrated the model by adjusting the short-run marginal cost merit orders in each of the countries studied in detail (except Belgium) so as to reproduce the annual (baseload and peak) forward prices for 2005. The Belgian merit order was adjusted so that the differential between Belgian and Dutch prices matched that seen historically. For the remaining years studied (2006-2010), the merit order adjustments were held constant.

Dutch market assumptions

We had previously received from TenneT data on centrally despatched demand and the appropriate plant list to use for generator studies with this demand. We have continued to use this dataset but we updated the generation capacities in line with the values contained in the “operating capacities and fuel type” spreadsheet recently published by TenneT. Announced capacity additions and an estimate of the likely growth in wind generation are then added in.

Dutch demand was assumed to grow at 1.5% per annum until 2005 and at 2% per annum thereafter. Table 11 shows how peak demand and installed capacity vary over time, under our base case (no contracts). Under this scenario 1.4 GW of gas plant is assumed to retire by the beginning of 2005, these are predominantly old, small, inefficient gas turbines.

Table 11: Dutch peak demand and generating capacity without contracts

	2004	2005	2006	2007	2008	2009	2010
Peak demand (GW)	12.8	13.0	13.2	13.5	13.8	14.0	14.3
Installed capacity (GW)							
Wind	0.5	0.8	0.8	0.9	0.9	0.9	1.0
Coal	4.3	4.3	4.3	4.3	4.3	4.3	4.3
Gas	10.7	10.1	10.5	10.5	10.5	10.5	10.5
Nuc	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total	16.0	15.6	16.1	16.1	16.1	16.2	16.2

Modelling regulating and PTU reserve

We have modelled the effect of both the existing regulating reserve (where we assume that, on average, 500 MW is available) and additional PTU reserve by reducing the availability of “running” plants. We have defined running plants to be those that, on average, operate at an annual load factor of 10% or less (although in an individual year, their load factor may be as high as 20%). This reduction in availability is applied uniformly across the year and the amount of reserve created by this method is simply measured as the reduction in availability of a plant multiplied by its capacity.

Appendix II : Effect of slow-response reserve on balancing prices and verification

The effect of slow response reserve on prices

In section 3.3, we discussed the effect that using slow-response reserve could have on balancing prices. In this appendix we describe the methodology behind our calculation.

We investigate by how much the cost of balancing for TenneT in 2003 would have been lower if TenneT had in some PTUs used slow response reserve instead of regulation. We calculate what balancing prices would have been in 2003 if TenneT had used slow reserve in certain PTUs. We compare these balancing prices with the actual prices in 2003. We take the extreme case in which TenneT has perfect foresight and is able to predict future imbalances perfectly. Consequently, we estimate the maximum possible cost reduction from using slow response reserve.

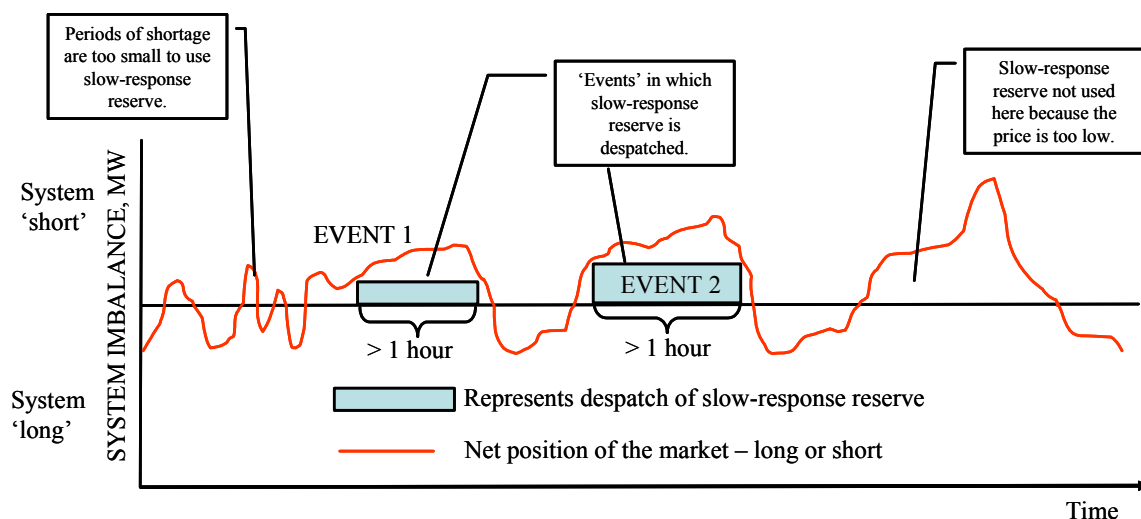
Slow response reserve is only useful in certain circumstances. For example, it can only be used when there is a shortage of power. In addition, slow response reserve has a response time of over 15 minutes. Hence, it is only worthwhile calling slow response reserve if the power shortage is expected to persist for several PTUs. Therefore, slow response reserve could not have been used during every PTU in 2003.

To identify the PTUs for which the use of slow response reserve was possible, we use information provided on TenneT’s website. TenneT lists the ‘regulation state’ for each PTU. The ‘regulation state’ indicates in each PTU whether negative power only was dispatched (*i.e.* there was a shortage), positive power only was dispatched (*i.e.* there was a surplus), both positive and negative power were dispatched, or no power was

dispatched. We consider only those PTUs in which there was a shortage of power. We also exclude PTUs in which both negative and positive power was dispatched. To take account of the response time of slow response reserve, we also restrict our analysis to cases in which the power shortage persisted for at least four consecutive PTUs (*i.e.* one hour).

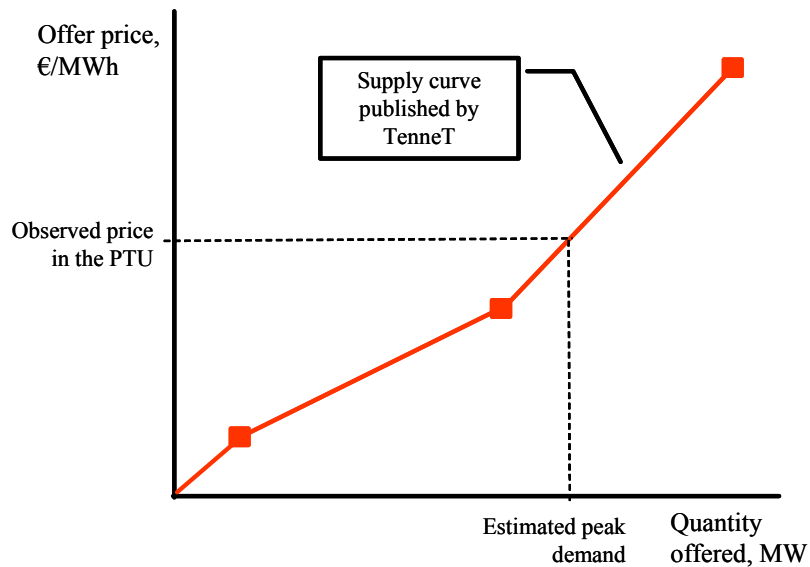
We then exclude series of PTUs for which the use of slow response reserve would raise the cost of balancing. We assume an offer price for slow response reserve of €150/MWh, and so exclude series of PTUs for which the average 2003 balancing price was less than €150/MWh. We assume that the balancing power required during these PTUs would continue to be supplied by regulation power and that the balancing price would be the same as in 2003. Figure 16 shows an illustration of system imbalance, and how imbalance events cause slow-response reserve to be used. Slow-response reserve is not used when the imbalance duration is too short or the price is too low.

Figure 16: Illustration of when slow-response reserve could be used



Once we have identified a series of four or more PTUs where the use of slow-response reserve would reduce the average balancing price, we need to calculate the quantity of slow response reserve required in each PTU. We first use interpolation to determine the maximum quantity of balancing power used in each PTU. TenneT publishes a ‘supply curve’ of offer prices for increasing quantities of upward regulation. We make the assumption that the price for a zero quantity of power is zero. Combining the supply curve with the observed balancing price allows us to estimate the peak power supply for each PTU (Figure 17 illustrates).

Figure 17: Estimating the peak demand in a PTU from the observed price



We amend some of our estimates to take account of problems with the data. For example, the TenneT data suggest that in some PTUs the supply curve is downward sloping. To calculate the maximum quantity of power used in these PTUs, we use using a supply curve equation based on the average of those for the other PTUs.

We then calculate the quantity of slow response reserve power required in each PTU. Because we assume that the amount of slow-response reserve called will be constant over the sequence of PTUs, the quantity of slow-response reserve called is based on the *minimum* demand for balancing power over the sequence of PTUs that slow-response reserve is used. We set the amount of slow-response reserve called at 70% of the smallest peak demand in the sequence of PTUs over which slow-response reserve is used. We assume that slow response reserve can only be dispatched in multiples of 5MW. We modify our values to take account of this.

We then recalculate the maximum amount of regulating power required in each PTU as the difference between the maximum balancing power required and the calculated amount of slow response reserve required. In other words, we assume that regulating power provides the difference between the demand for balancing power and what slow-response reserve provides.

We then calculate the new price, after slow-response reserve is used. We take the maximum quantity of regulation required after slow-response reserve is despatched, and read-off the new balancing price using the interpolation described previously (*i.e.* in Figure 17).

We assume that TenneT caps the offer-price of providers of slow-response reserve at 200 €/MWh. However, generators will not always offer at their offer cap level, because by offering at a lower level increasing their chance of profitable despatch. Therefore, we assume that the average energy-price offer from providers of slow-response reserve is 150 €/MWh. If the ‘new’ price calculated in the step above is below 150 €/MWh, we

overwrite the calculated price with a price of 150 €/MWh. In this case, slow-response reserve sets the price.

We calculate actual average balancing prices in 2003. We compare these with the average balancing prices which apply when slow response reserve can be used for balancing. Table 7 on page 26 shows the results of our calculations.

Verification

In section 4.5, we claimed that it would be possible to test about 1700 MW per month of slow-response reserve, while reducing balancing prices and costs. We arrive at this number as follows. The exercise described in the previous sections identifies when and how much slow-response reserve would be called during each month. Typically, every month will have several ‘events’ where slow-response reserve is used for at least four PTUs. Each of these events is an opportunity to test an amount of slow-response reserve capacity. By adding up the capacity called in each of these events during the month, we determine the total amount of capacity that TenneT could test while reducing average prices. For example, if slow-response reserve was called in three separate events in February, and the amounts called for the first, second and third events were 150 MW, 200 MW and 100 MW respectively, it would be possible to test 450 MW of slow-response reserve during February, without increasing balancing costs. Table 12 details the results.

Table 12: Amount of verification possible per month

Month	Quantity (MW) of slow response that could be tested, MW
January	520
February	760
March	210
April	365
May	880
June	1080
July	1645
August	3175
September	1440
October	3845
November	3330
December	3465
Average	1,726

Appendix III : Methodology for calculating profits in the balancing and APX markets

In Figure 7, we show the profit a generator could make by offering 1 MW on the APX or as upward regulating power on the balancing market. In this appendix we explain our methodology for calculating the profit in these two markets in more detail. We calculate the profit that the generator could have earned on each market in 2003 and 2002, for a range of offer prices. Since 1MW is a small proportion of total capacity in the Netherlands, the availability of the additional 1MW will have no impact on the observed market prices.

Calculating profit in the balancing market

To calculate the generator's profit in the balancing market, we use prices from TenneT's website. TenneT lists the price for upward dispatch for each PTU in 2003 and 2002. We assume that if the price for upward dispatch in the balancing market exceeds the generator's offer price, the generator is dispatched and earns a profit. If the generator's offer price is below the prevailing balancing market price he is not despatched.

If the generator is dispatched for a full PTU, his profit for the PTU is:

Profit (€) = 1MW x (price for upward dispatch (€/MWh) – generator's offer price €/MWh) x 0.25 hours

However, this calculation is likely to overestimate the generator's profit. We cannot assume that the generator's MW is dispatched for the full PTU, as soon as his offer price is below the prevailing balancing price. In reality, the generator's MW may only be called partially and for a fraction of the PTU. We need to correct for this problem by multiplying the profit calculated above by a load factor that reflects how much power the generator despatches in a PTU. Calculating this load factor is difficult, because we lack information about the pattern of despatch *within* a PTU. Therefore, we consider two alternative methods of calculating the load factor. First, we calculate an average load factor per PTU, defined as the average power deployed during a PTU, divided by the maximum power deployed during the PTU. TenneT does not provide such load factors but does provide data on the total ramp-up energy (MWh) deployed in a PTU. The average power deployed in a PTU is simply the number of MWh despatched in the PTU multiplied by four. For example, if 20 MWh of energy were despatched in a (fifteen minute) PTU, the average power used must be 80 MW.

As described in Appendix II and illustrated in Figure 17, we estimate the maximum quantity of power used in a PTU based on the observed price in the PTU. Dividing the average power used by the maximum power supplied yields an *average* load factor for each PTU.

However, if the generator's offer price is very low relative to the prevailing balancing price, he will likely have a higher than average load factor during the PTU. In effect, he will act as base-load power, possibly running for the entire PTU. Using the average load

factor may underestimate the generator's profits. To account for this, we calculate an adjusted set of load factors based on the difference between the generator's offer price and the balancing price in the PTU. For every PTU, we derive a linear relationship between a generator's offer price and load factor. We assume that the generator with the lowest offer price has a load factor of twice the average load factor for the PTU, and we ensure that the average load factor is as calculated above. By applying this linear relationship, we ensure that if the generator's offer price is near to the balancing price, he will have a lower load factor. Conversely if the generator's offer is much lower than the balancing price, he will have a relatively high load factor.

Figure 7 shows that the calculated profits in the balancing market are sensitive to our assumptions about load factors. When we use average load factors, balancing market profit is lower than APX profit. However, when we weight the load factor according to the generator's offer price, the profit on the balancing market exceeds that on the APX.

We then calculate generator profit per 15 minute period as:

Profit (€) = 1MW x (price for upward dispatch (€/MWh) – generator's offer price of 30€/MWh) x 0.25 hours x 'generator load factor'.

The generator earns zero profit if his offer price exceeds the balancing market price for upward dispatch.

We add the profit for each 15 minute period of the year to obtain the generator profit on the balancing market.

Calculating profit on the APX

The APX quotes prices on an hourly basis. If a generator's offer price is less than the APX price, the generator is dispatched for the full hour and receives a profit of:

Profit (€) = 1MW x (APX price (€/MWh) – generator's offer price of 30€/MWh) x 1 hour

Otherwise, he receives nothing.

We add the profit for each hour of the year to obtain a figure for annual profit.

A higher volatility of profits in the balancing market could provide an incentive for generators to participate in the APX even if the expected profit was lower. We calculate the standard deviation of profits a generator could have expected from each market in 2002-3. We find that the volatility of profit was greater in the APX, but not significantly so.

Appendix IV : Balancing market vs. Self-balancing

In section 4.6, we claimed that it was always optimal for generators to offer power in the balancing market, if they were able to meet the 15 minute start-up criteria. In this appendix we give more background to this claim.

Consider a generator with 500 MW of generation, made up of five 100 MW units. The generator decides to hold 100 MW as reserve, to cover the event of a failure in one of the other generating units. The generator nominates 400 MW in his E-programme, so that he has 100 MW ‘spare’. The generator could either offer the spare 100 MW in the balancing market (we assume it the generator can ramp up within the required time, perhaps by running five units at a 80 MW each) or keep the power for ‘self-balancing’.

First consider what happens if the anticipated 100 MW failure occurs, and the generator has kept 100 MW back for self-balancing. The generator can simply ramp up production to replace the lost power production. He is not out of balance, and does not have to buy power in the balancing market.

Next, we consider what happen if the generator has offered power in the balancing market. There are two possibilities. First, the generator’s offer of upward balancing power has been taken up, so the spare capacity is already despatching in the balancing market. When the failure occurs, the generator has no ‘spare’ power available. The generator is out of balance, and will have to buy 100 MW of balancing power at the prevailing price. However, the generator receives offsetting income for 100 MW of balancing power, *at exactly the same price*.⁵⁶ Therefore, the generator is financially neutral.

The second possibility is that the failure occurs and the generator’s offer in the balancing market is not called *i.e.* his spare capacity is not generating, so he has no offsetting income. However, the generator is always free to despatch the 100 MW of generation himself. The generator can still self-balance, even if the power has been offered in the balancing market. It makes no difference if the market is net long or net short. If the generator’s balancing market offer is called, and he is already running, he simply becomes a Regulation and Reserve Power Supplier (RRPS). This an administrative detail only, and makes no difference to the generator’s financial neutrality.

The example illustrates that by offering power in the balancing market, the generator is no worse off than if he keeps power for self-balancing. Offering power in the balancing market does not restrict the generator’s ability to self-balance. However, it provides profitable opportunities to sell the ‘spare’ power in the balancing market, during the majority of the time when the generator does not experience a failure. If the generator keeps the power for self-balancing, he will never be called in the balancing market, and misses opportunities for profitable generation. We conclude that, if a generator had power that could meet the 15 minutes despatch criteria of the balancing market, it would always

⁵⁶ The exception to this is when the incentive component is applied, which creates a difference between what RRPSs receive and PRPs pay. However, the incentive component is rarely applied, and when it is applied it is very small.

be profit maximising to offer this power in the balancing market. The only reason a generator would not offer power in the balancing market was if he could not meet the 15 minutes start-up criteria.

Appendix V : Details of the costs of additional reserve

Figure 5 and Figure 6 show the cost of additional regulation reserve contracts and slow-response reserve. We describe the costs in more detail below, for both the slow-response product and the PTU reserve product.

Slow-response product

We assume that peak-plant take up contracts for the slow-response reserve, and the contract payments must cover peaks-plants fixed costs. Peak plant fixed costs have two main elements; fixed operating costs, such as salaries and plant maintenance; and costs for gas transportation. Contracting peak plant for reserve does not change the merit order, so there is no change in despatch relative to the base case. Table 13 and Table 14 give details of the costs of 500MW and 950MW of slow response reserve respectively.

Table 13: Costs of 500 MW of slow-response reserve

		2005	2006	2007	2008	2009	2010
Plant fixed costs (€m)	[1] TBG	4.0	4.1	4.1	4.2	4.3	4.3
Plant gas transportation costs							
Base load entry charge, €/m3/h/year	[2] See note	15.30	15.61	15.92	16.24	16.56	16.89
Peak load entry charge capacity, €/m3/h/year	[3] See note	22.44	22.89	23.35	23.81	24.29	24.78
Exit capacity tariff, €/m3/h/year	[4] See note	19.16	19.54	19.93	20.33	20.73	21.15
Connection tariff, €/m3/h/year	[5] Gasunie	20.97	21.39	21.82	22.25	22.70	23.15
Plant efficiency	[6] TBG	42%	42%	42%	42%	42%	42%
Plant load factor	[7] TBG	3%	3%	3%	3%	3%	3%
Capacity of contracts (MW)	[8] TBG	491	491	491	491	491	491
Gas Capacity (kW gas/kW electricity)	[9] 1/[6]	2.4	2.4	2.4	2.4	2.4	2.4
Capacity (m3/h)	[10] [9]x3.6/35.17	0.24	0.24	0.24	0.24	0.24	0.24
Volume (m3)	[11] [10]x[7]x8760	64	64	64	64	64	64
Baseload Capacity (m3/h)	[12] [10]/8760	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073
Additional Capacity (m3/h)	[13] [10]-[12]	0.24	0.24	0.24	0.24	0.24	0.24
System Fee (€/kW/year)	[14] [2]x[12]+[3]x[13]	5.42	5.53	5.64	5.75	5.86	5.98
Exit Fee (€/kW/year)	[15] [4]x[10]	4.67	4.76	4.86	4.95	5.05	5.15
Connection Fee (€/kW/year)	[16] [5]x[10]	5.11	5.21	5.32	5.42	5.53	5.64
Total gas transport fees (€/kW/year)	[17] [14]+[15]+[16]	15.20	15.50	15.81	16.13	16.45	16.78
Total gas transport costs (€m)	[18] [17]x[8]/1000	7.46	7.61	7.76	7.92	8.08	8.24
Total costs of slow-response reserve (€m)	[19] [18]+[1]	11.45	11.69	11.90	12.12	12.34	12.57

Notes

TBG = Calculation or assumption by The Brattle Group.

[2],[3]: Based on 2004 charges inflated at 2% per year.

[4]: Based on average GTS exit charge in 2004, inflated at 2% per year.

Table 14: Costs of 950 MW of slow-response reserve

			2005	2006	2007	2008	2009	2010
Plant fixed costs (€m)	[1]	TBG	7.7	7.9	8.0	8.1	8.2	8.3
Plant gas transportation costs								
Base load entry charge, €/m3/h/year	[2]	See note	15.30	15.61	15.92	16.24	16.56	16.89
Peak load entry charge capacity, €/m3/h/year	[3]	See note	22.44	22.89	23.35	23.81	24.29	24.78
Exit capacity tariff, €/m3/h/year	[4]	See note	19.16	19.54	19.93	20.33	20.73	21.15
Connection tariff, €/m3/h/year	[5]	Gasunie	20.97	21.39	21.82	22.25	22.70	23.15
Plant efficiency	[6]	TBG	42%	42%	42%	42%	42%	42%
Plant load factor	[7]	TBG	3%	3%	3%	3%	3%	3%
Capacity of contracts (MW)	[8]	TBG	946	946	946	946	946	946
Gas Capacity (kW gas/kW electricity)	[9]	1/[6]	2.4	2.4	2.4	2.4	2.4	2.4
Capacity (m3/h)	[10]	[9]x3.6/35.17	0.24	0.24	0.24	0.24	0.24	0.24
Volume (m3)	[11]	[10]x[7]x8760	64	64	64	64	64	64
Baseload Capacity (m3/h)	[12]	[10]/8760	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073
Additional Capacity (m3/h)	[13]	[10]-[12]	0.24	0.24	0.24	0.24	0.24	0.24
System Fee (€/kW/year)	[14]	[2]x[12]+[3]x[13]	5.42	5.53	5.64	5.75	5.86	5.98
Exit Fee (€/kW/year)	[15]	[4]x[10]	4.67	4.76	4.86	4.95	5.05	5.15
Connection Fee (€/kW/year)	[16]	[5]x[10]	5.11	5.21	5.32	5.42	5.53	5.64
Total gas transport fees (€/kW/year)	[17]	[14]+[15]+[16]	15.20	15.50	15.81	16.13	16.45	16.78
Total gas transport costs (€m)	[18]	[17]x[8]/1000	14.38	14.66	14.96	15.26	15.56	15.87
Total costs of slow-response reserve (€m)	[19]	[18]+[1]	22.05	22.52	22.93	23.35	23.78	24.21

Notes

TBG = Calculation or assumption by The Brattle Group.

[2],[3]: Based on 2004 charges inflated at 2% per year.

[4]: Based on average GTS exit charge in 2004, inflated at 2% per year.

PTU reserve product

The PTU reserve product results in an additional – and significant – cost relative to the slow-response reserve product. High variable-cost peak plant replaces low variable-cost plant that generators have withdrawn to provide PTU reserve. As a result, electricity generation costs increase. This is shown in row 20 of Table 15 and Table 16, which detail the costs of 500 MW and 950 MW of PTU reserve respectively.

Table 15: Costs of 500 MW of PTU reserve

			2005	2006	2007	2008	2009	2010
Plant fixed costs (€m)	[1]	TBG	4.0	4.1	4.1	4.2	4.3	4.3
Plant gas transportation costs								
Base load entry charge, €/m3/h/year	[2]	See note	15.3	15.6	15.9	16.2	16.6	16.9
Peak load entry charge capacity, €/m3/h/year	[3]	See note	22.4	22.9	23.3	23.8	24.3	24.8
Exit capacity tariff, €/m3/h/year	[4]	See note	19.2	19.5	19.9	20.3	20.7	21.1
Connection tariff, €/m3/h/year	[5]	Gasunie	21.0	21.4	21.8	22.3	22.7	23.2
Plant efficiency	[6]	TBG	42%	42%	42%	42%	42%	42%
Plant load factor	[7]	TBG	8%	8%	8%	8%	8%	8%
Capacity of contracts (MW)	[8]	TBG	491	491	491	491	491	491
Gas Capacity (kW gas/kW electricity)	[9]	1/[6]	2.4	2.4	2.4	2.4	2.4	2.4
Capacity (m3/h)	[10]	[9]x3.6/35.17	0.24	0.24	0.24	0.24	0.24	0.24
Volume (m3)	[11]	[10]x[7]x8760	160	160	160	160	160	160
Baseload Capacity (m3/h)	[12]	[10]/8760	0.0183	0.0183	0.0183	0.0183	0.0183	0.0183
Additional Capacity (m3/h)	[13]	[10]-[12]	0.2	0.2	0.2	0.2	0.2	0.2
System Fee (€/kW/year)	[14]	[2]x[12]+[3]x[13]	5.3	5.4	5.6	5.7	5.8	5.9
Exit Fee (€/kW/year)	[15]	[4]x[10]	4.7	4.8	4.9	5.0	5.1	5.2
Connection Fee (€/kW/year)	[16]	[5]x[10]	5.1	5.2	5.3	5.4	5.5	5.6
Total gas transport fees (€/kW/year)	[17]	[14]+[15]+[16]	15.1	15.4	15.7	16.0	16.4	16.7
Total gas transport costs (€m)	[18]	[17]x[8]/1000	7.4	7.6	7.7	7.9	8.0	8.2
Total fixed costs (€m)	[19]	[18]+[1]	11.41	11.65	11.86	12.08	12.30	12.52
Additional variable costs as a result of PTU reserve								
Increase in peak plant output (TWh)	[20]	TBG	4.0	2.2	2.1	2.0	1.2	1.4
Decrease in baseload plant output (TWh)	[21]	TBG	-13.2	-5.8	-1.7	-1.7	-3.5	-3.6
Change in marginal costs of domestic plant (€m)	[22]	TBG	-114.9	-31.0	30.7	27.4	-13.8	-11.2
Change in net costs of imports (€m)	[23]	TBG	278.3	111.6	-9.9	-5.9	41.7	58.9
Increase in marginal cost due to use of PTU reserve, (€m)	[24]	TBG	163.4	80.5	20.8	21.5	27.9	47.7
System fee, (€m)	[25]	[8]x[14]/1000	2.6	2.7	2.7	2.8	2.8	2.9
Total cost of PTU reserve, (€m)	[26]	[19]+[24]-[25]	172.1	89.5	30.0	30.8	37.3	57.3

Notes

TBG = Calculation or assumption by The Brattle Group.

[2],[3]: Based on 2004 charges inflated at 2% per year.

[4]: Based on average GTS exit charge in 2004, inflated at 2% per year.

Table 16: Costs of 950 MW of PTU reserve

			2005	2006	2007	2008	2009	2010
Plant fixed costs (€m)	[1]	TBG	7.7	7.9	8.0	8.1	8.2	8.3
Plant gas transportation costs								
Base load entry charge, €/m3/h/year	[2]	See note	15.3	15.6	15.9	16.2	16.6	16.9
Peak load entry charge capacity, €/m3/h/year	[3]	See note	22.4	22.9	23.3	23.8	24.3	24.8
Exit capacity tariff, €/m3/h/year	[4]	See note	19.2	19.5	19.9	20.3	20.7	21.1
Connection tariff, €/m3/h/year	[5]	Gasunie	21.0	21.4	21.8	22.3	22.7	23.2
Plant efficiency	[6]	TBG	42%	42%	42%	42%	42%	42%
Plant load factor	[7]	TBG	8%	8%	8%	8%	8%	8%
Capacity of contracts (MW)	[8]	TBG	946	946	946	946	946	946
Gas Capacity (kW gas/kW electricity)	[9]	1/[6]	2.4	2.4	2.4	2.4	2.4	2.4
Capacity (m3/h)	[10]	[9]x3.6/35.17	0.24	0.24	0.24	0.24	0.24	0.24
Volume (m3)	[11]	[10]x[7]x8760	160	160	160	160	160	160
Baseload Capacity (m3/h)	[12]	[10]/8760	0.0183	0.0183	0.0183	0.0183	0.0183	0.0183
Additional Capacity (m3/h)	[13]	[10]-[12]	0.2	0.2	0.2	0.2	0.2	0.2
System Fee (€/kW/year)	[14]	[2]x[12]+[3]x[13]	5.3	5.4	5.6	5.7	5.8	5.9
Exit Fee (€/kW/year)	[15]	[4]x[10]	4.7	4.8	4.9	5.0	5.1	5.2
Connection Fee (€/kW/year)	[16]	[5]x[10]	5.1	5.2	5.3	5.4	5.5	5.6
Total gas transport fees (€/kW/year)	[17]	[14]+[15]+[16]	15.1	15.4	15.7	16.0	16.4	16.7
Total gas transport costs (€m)	[18]	[17]x[8]/1000	14.3	14.6	14.9	15.2	15.5	15.8
Total fixed costs (€m)	[19]	[18]+[1]	22.0	22.4	22.9	23.3	23.7	24.1
Additional variable costs as a result of PTU reserve								
Increase in peak plant output (TWh)	[20]	TBG	5.5	3.0	2.5	2.3	1.7	2.0
Decrease in baseload plant output (TWh)	[21]	TBG	-17.2	-8.3	-1.7	-1.7	-6.2	-6.3
Change in marginal costs of domestic plant (€m)	[22]	TBG	-137.4	-50.5	43.2	37.2	-39.6	-37.2
Change in net costs of imports (€m)	[23]	TBG	351.3	154.8	-30.0	-18.2	98.3	113.4
Increase in marginal cost due to use of PTU reserve, (€m)	[24]	TBG	213.9	104.3	13.1	19.0	58.7	76.2
System fee, (€m)	[25]	[8]x[14]/1000	5.1	5.2	5.3	5.4	5.5	5.6
Total cost of PTU reserve, (€m)	[26]	[19]+[24]-[25]	230.8	121.6	30.7	36.9	77.0	94.7

Notes

TBG = Calculation or assumption by The Brattle Group.

[2],[3]: Based on 2004 charges inflated at 2% per year.

[4]: Based on average GTS exit charge in 2004, inflated at 2% per year.

Appendix VI : Relationships between APX Prices, Balancing Prices, OTC Prices, and Price Volatility

The introduction of additional long-term contracts for balancing power could affect balancing prices. Changes in balancing prices may feed through to APX and OTC prices, because these prices are based in part on the expectation of balancing prices. Changes in balancing price volatility may also change the spread between the APX price and the balancing market price, as market participants are prepared to pay a higher price day-ahead if the balancing price becomes more volatile.

We use regression analysis to determine the strength of the relationships between APX and OTC prices and balancing prices and volatility.

APX Prices and Balancing Prices

We test whether day-ahead APX prices are influenced by balancing feed or take prices. We conduct the following six regressions:

1. $APX(t) = \alpha + \beta \text{ TenneT Take}(t-1)$
2. $\text{Peak APX}(t) = \alpha + \beta \text{ Peak TenneT Take}(t-1)$
3. $\text{Off-Peak APX}(t) = \alpha + \beta \text{ Off-Peak TenneT Take}(t-1)$
4. $APX(t) = \alpha + \beta \text{ TenneT Feed}(t-1)$
5. $\text{Peak APX}(t) = \alpha + \beta \text{ Peak TenneT Feed}(t-1)$
6. $\text{Off-Peak APX}(t) = \alpha + \beta \text{ Off-Peak TenneT Feed}(t-1)$

We aggregate the four quarter-hourly balancing prices to a single hourly price for comparison with the APX market. We compare the balancing price on the day the APX price was set, which is the day before they apply. Table 17 summarises our results.

Table 17: APX Regression Results

Regression	β Estimate		Test Statistics			Comment
	Estimate	St. Err.	R ²	t-stat	crit. Stat	
1 All Hours Take	0.48	0.04	0.28	11.6	2.3	Statistically and economically significant relationship
2 Peak Hours Take	0.57	0.05	0.34	11.5	2.3	Statistically and economically significant relationship
3 Off-Peak Hours Take	0.04	0.01	0.03	3.3	2.3	Statistically questionable due to low R ² .
4 All Hours Feed	0.59	0.05	0.33	12.1	2.3	Statistically and economically significant relationship
5 Peak Hours Feed	0.61	0.5	0.25	11.2	2.3	Statistically and economically significant relationship
6 Off-Peak Hours Feed	0.02	0.01	0.01	1.6	2.3	Stistically and economically insignificant

During peak hours there is a strong and significant relationship between both take and feed balancing prices and the APX price. During off-peak hours there is little significance at all.⁵⁷

OTC Prices and Balancing Prices

We test whether OTC prices, as reported by Platts, are influenced by balancing feed or take prices. We conduct the following 12 regressions:

1. Platts Day Ahead Peak (t) = $\alpha + \beta$ TenneT Peak Take (t)
2. Platts Day Ahead Off Peak (t) = $\alpha + \beta$ TenneT Off Peak Take (t)
3. Platts Day Ahead Peak (t) = $\alpha + \beta$ TenneT Peak Feed (t)
4. Platts Day Ahead Off Peak (t) = $\alpha + \beta$ TenneT Off Peak Feed (t)
5. Platts Weak Ahead Peak (t) = $\alpha + \beta$ TenneT 5 day Rolling Peak Take (t)
6. Platts Weak Ahead Off Peak (t) = $\alpha + \beta$ TenneT 5 day Rolling Off Peak Take (t)
7. Platts Weak Ahead Peak (t) = $\alpha + \beta$ TenneT 5 day Rolling Peak Feed (t)
8. Platts Weak Ahead Off Peak (t) = $\alpha + \beta$ TenneT 5 day Rolling Off Peak Feed (t)
9. Platts Month Ahead Peak (t) = $\alpha + \beta$ TenneT 20 day Rolling Peak Take (t)
10. Platts Month Ahead Off Peak (t) = $\alpha + \beta$ TenneT 20 day Rolling Off Peak Take (t)
11. Platts Month Ahead Peak (t) = $\alpha + \beta$ TenneT 20 day Rolling Peak Feed (t)
12. Platts Month Ahead Off Peak (t) = $\alpha + \beta$ TenneT 20 day Rolling Off Peak Feed (t)

We calculate time-weighted daily average balancing prices from quarter-hourly data published by TenneT. We also calculate 5 and 20 day rolling average prices to capture the effect that medium-term movements in the balancing price have on medium-term forward prices.

Table 18 summarises our results.

⁵⁷ Peak hours are defined as between 7:00am and 11:00pm inclusive, Monday to Friday. All other hours are defined as Off-Peak.

Table 18: OTC Regression Results

Regression	β Estimate		Test Statistics			Comment
	Estimate	St. Err.	R ²	t-stat	crit. Stat	
1 DA Peak Hours Take	0.27	0.03	0.32	10.8	2.3	Statistically and economically significant relationship
2 DA Off-Peak Take	0.33	0.07	0.07	5	2.3	Statistically questionable due to low R ² .
3 DA Peak Hours Feed	0.29	0.03	0.31	10.3	2.3	Statistically and economically significant relationship
4 DA Off-Peak Feed	0.37	0.07	0.1	5.1	2.3	Statistically questionable due to low R ² .
5 WA Peak Hours Take	0.3	0.03	0.35	11.4	2.3	Statistically and economically significant relationship
6 WA Off-Peak Take	0.42	0.05	0.21	7.9	2.3	Statistically and economically significant relationship
7 WA Peak Hours Feed	0.32	0.3	0.35	11.4	2.3	Statistically and economically significant relationship
8 WA Off-Peak Feed	0.29	0.05	0.17	6.1	2.3	Statistically and economically significant relationship
9 MA Peak Hours Take	0.19	0.02	0.29	9.8	2.3	Statistically and economically significant relationship
10 MA Off-Peak Take	0.29	0.04	0.19	7.4	2.3	Statistically and economically significant relationship
11 MA Peak Hours Feed	0.21	0.02	0.28	9.5	2.3	Statistically and economically significant relationship
12 MA Off-Peak Feed	0.12	0.05	0.03	2.5	2.3	Statistically questionable due to low R ² .

In the Day-Ahead regressions (1-4), the off-peak relationship remains weak, while the peak relationship remains similarly strong. In the Week Ahead and Month Ahead regressions the off-peak relationship appears to get stronger.

APX – Balancing price spread and Balancing Price Volatility

We also investigate a possible relationship between balancing market price volatility and the spread between the APX and the Balancing Market Price. In particular, an increase in balancing price volatility may lead to an increase in the spread between the two markets since market participants may be prepared to pay extra for the relative price stability of the APX.

We calculate the average price differential between the two markets across a week. We compare this with the volatility in the balancing market across the same week.

We calculate our index for volatility as the standard deviation of the log of the changes in day to day prices. A sample week is given in Table 19.

Table 19: Volatility Calculation

Day	Price [A]	Change in Price [B] $/[A]t - [A]t-1/$	Ln Change in Price [C] $Ln [B]$
Sun	36		
Mon	23	13	2.56
Tue	21	2	0.69
Wed	7	14	2.64
Thu	15	8	2.08
Fri	2	13	2.56
Sat	14	12	2.48
Sun	3	11	2.40
Volatility	<i>STDEV [C]</i>		0.69

We ran the following six regressions:

1. Apx-Tenant Take Spread (t) = $\alpha + \beta$ TenneT Take Volatility (t)
2. Peak Apx-Tenant Take Spread (t) = $\alpha + \beta$ Peak TenneT Take Volatility (t)
3. Off Peak Apx-Tenant Take Spread (t) = $\alpha + \beta$ Off Peak TenneT Take Volatility (t)
4. Apx-Tenant Feed Spread (t) = $\alpha + \beta$ TenneT Feed Volatility (t)
5. Peak Apx-Tenant Feed Spread (t) = $\alpha + \beta$ Peak TenneT Feed Volatility (t)
6. Off Peak Apx-Tenant Feed Spread (t) = $\alpha + \beta$ Off Peak TenneT Feed Volatility (t)

Our results are summarised in Table 20.

Table 20: Volatility Regressions

Regression	Gradient Estimate		Test Statistics			Comment
	Estimate	St. Err.	R2	t-stat	crit. Stat	
1 All Hours Take	11.7	3.6	0.18	3.3	2.3	While some of the results are statistically significant, we can see no clear pattern. In addition, there should be no reason why the relationship with feed volatility should be so much weaker than the relationship with take volatility.
2 Peak Hours Take	9	3	0.15	3	2.3	
3 Off-Peak Hours Take	20.2	8.6	0.1	2.35	2.3	
4 All Hours Feed	7.2	4	0.06	1.8	2.3	
5 Peak Hours Feed	-5.3	4	0.03	1.3	2.3	
6 Off-Peak Hours Feed	21.8	7.6	0.14	2.8	2.3	

Conclusions

There is strong evidence of a correlation between on-peak day-ahead prices (both APX and OTC) and balancing prices. There is also strong evidence of little or no correlation between off-peak day-ahead prices and balancing prices.

There also seems to be strong evidence of a correlation between week-ahead and month-ahead OTC prices with historical balancing prices, though the reason for the increased correlation in off-peak time periods is unclear.

We draw no conclusions about the relationship between volatility and the spread between the APX and balancing market prices since our methodology provides distinctly un-intuitive results about the difference between the take and feed markets.

Appendix VII : Incentive regulation in England and Wales

The British energy regulator (Ofgem) has operated an incentive regulation scheme for National Grid Company (NGC, the System Operator in England and Wales) since the winter of 1994/95. Under the scheme, NGC and Ofgem agree a target for the costs of balancing the electricity system in England and Wales. If the actual balancing costs are below the target cost, NGC is allowed to keep a proportion of the saving. Conversely, if actual costs are above the target, NGC must pay the difference, and its profits are reduced. Under the current scheme, Ofgem apply a 'collar' and 'cap' system, in which both the amount NGC must payout and the savings it is allowed to keep are limited. To date, Ofgem and NGC have agreed a new target balancing cost every year. Revising the cost targets annually probably undermines the incentive for NGC to save money, because it realises that a large cost saving in one year will likely lead to a reduced cost target in the following year, making future cost under-runs more difficult. However, to date frequent structural changes in the British electricity market have made it difficult to establish a longer term target.

For example, the introduction of the New Electricity Trading Arrangements (NETA) in 2001 led NGC to argue that the cost of balancing the system would increase substantially; NGC estimated balancing costs of £542 million for the year, while Ofgem thought the cost would be lower at £471 million. Ofgem offered NGC one of four reward schemes (illustrated in Figure 18), which varied in the level of risk and reward offered. The realised costs for 2001/02 were £366 million, well below even Ofgem's cost estimate. As a result, NGC earned a bonus or 'incentive payment' of £46.3 million, the maximum possible under their chosen reward scheme. Unsurprisingly, the 2002 balancing cost target was set lower at £460 million.⁵⁸

Following the introduction of NETA, plans to introduce a single electricity market for Great Britain (as opposed to having a market for England & Wales and another for Scotland), as well as other smaller changes in market rules, have ruled out the introduction of a longer-term incentive scheme for NGC. Nevertheless, despite the short term nature of NGC's incentive scheme, it has yielded impressive cost reductions. Since the introduction of an incentive scheme, costs have fallen by over 65% between 1994 and 2001. Figure 19 illustrates balancing costs in England and Wales following the introduction of an incentive scheme. NGC's bonuses have also been impressive, averaging £15 million a year pre-NETA and £47 million thereafter.

⁵⁸ This target cost may seem high relative to the realized costs for the previous year. However, in gate closure had moved from four hours to one hour, and NGC claimed this would result in increased balancing costs. Consequently, Ofgem set a generous cost target. In fact, the actual balancing costs were £379 million, which represented less than a 4% increase on the previous year with the longer gate-closure.

Figure 18: Alternative reward schemes for NGC in 2001/2

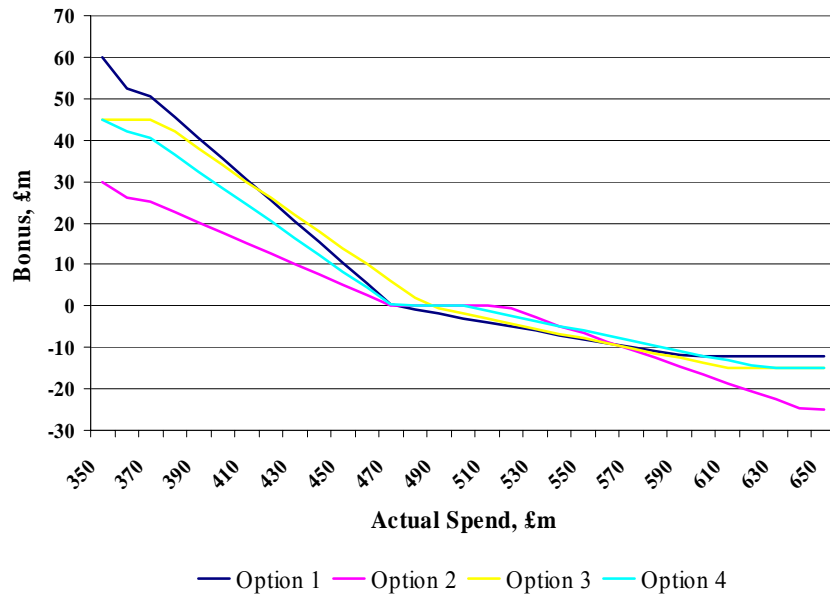
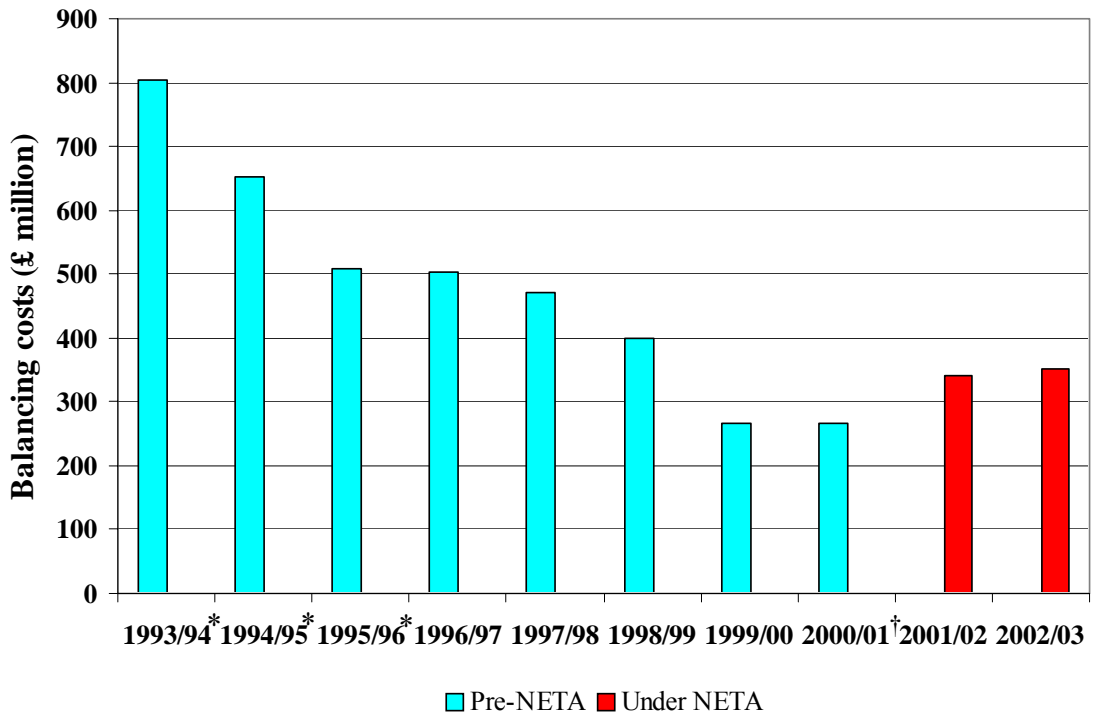


Figure 19: System operation costs in England and Wales



* Transmission losses estimated for these years

† Costs assumed equal to 1999/00