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Reform of NTS Gas Offtake Arrangements

Report for the Gas Forum

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Executive Summary

Background

As part of the Transmission Price Control Review (TPCR) process, Ofgem and National Grid have consulted on and developed new business rules that define new arrangements for selling NTS exit capacity. National Grid has submitted the new rules as Modification 116 to the Uniform Network Code (UNC).

Modification 116 ("Mod 116") separates NTS exit capacity into (1) **flat capacity**, which would allow users to take gas off the NTS at a *constant* rate over the day, and (2) **flexibility capacity**, which would allow users to *vary* their rate of offtake over the day. Users would need flexibility capacity on all days, but would only be charged for overruns on "flexibility constraint days", which National Grid might declare at any time (not just winter peaks).

Three signatories to the UNC have put forward alternative modification proposals. Mod 116A would extend indefinitely the current arrangements for exit capacity charging. Mod 116C would introduce only the flat capacity product. Mod 116B is a refinement of Mod 116 and would introduce both flat and flexibility products.

In addition, under Mods 116, 116C and 116B, National Grid would no longer offer let users book firm or interruptible exit capacity on an annual basis.

§ Existing users would acquire their "prevailing" (i.e. current) capacity as a *firm* commitment running up to September 2010.

§ Users would no longer be able to book *interruptible* exit capacity on an annual basis. (National Grid would only make it available on a daily basis.)

§ Users who wanted to extend their capacity commitment beyond October 2010 would have to commit to pay for capacity in years Y+4 to Y+7 from the time of the request. Hence. in the first instance, requests in 2007 would cover capacity from 2010/11 to 2013/14.

§ National Grid would auction off any unused exit capacity for years Y+1 to Y+3 in a cycle of annual and day-ahead auctions.

The new long-term commitments to pay for NTS exit capacity would replace ARCAs (Advance Revenue Commitment Agreements) as a way for users to agree to pay for investments in exit capacity. Ofgem sees this as a way to avoid potential discrimination.

The Gas Forum has commissioned NERA Economic Consulting to evaluate the economic case for the proposed reforms, as a contribution to Ofgem's consultation process.

Anticipated Problems with the Proposals

The proposed capacity arrangements are complex, unorthodox and alienated from basic concepts of pipeline capacity. The concept of "flexibility exit capacity" is particularly difficult to reconcile with underlying economic pipeline costs, but even flat exit capacity is a poorly defined concept because (a) it does not reflect peak deliverability and (b) like NTS exit capacity, it is unrelated to any particular route through the network.

The potential for setting prices in auctions is severely limited, because many exit points serve only one connected customer and because capacity is not interchangeable between exit points. As a result, the pricing of the proposed flat and flexibility exit capacity will largely depend on reserve prices set by National Grid. National Grid has outlined an approach to pricing which is not transparent. It will therefore (1) lead to distorted signals about the need for investment and (2) offer new opportunities for discrimination by National Grid.

Flexibility capacity creates particular problems for bi-directional exit points, such as interconnectors and gas storage. One user's need for flexibility capacity at bi-directional sites would depend on the injection and withdrawal profiles of other users at the same site.

The proposals for dealing with interruption run the risk of imposing inefficient costs on certain network users and deterring genuinely interruptible loads. In particular, if long-term interruptible customers (who impose no capacity costs on the network) are forced to book firm capacity, National Grid could mistake their request for firm capacity as a need to plan for a firm 1-in-20 offtake, and invest inefficiently in capacity that is not needed.

The removal of interruptible tariffs, among other factors, may have implications for security of supply in Great Britain. The proposed system will also affect competition in the British gas market. Its complexity will act as a barrier to entry into the gas shipping market. Competition with National Grid's offer of flexibility capacity will also be limited to gas storage within customers' sites and distribution networks, since the definition of entry and exit capacity does not permit users to compete with upstream storage or swing gas.

The proposed reforms will also affect competition and security of supply in the Irish gas market. Irish respondents were concerned that the new flexibility capacity would not link up well with capacity on the Irish interconnector, and that the award of exit capacity on the basis of "prevailing rights" to current users of the interconnector would limit entry into the Irish gas market. Irish respondents also identified a number of costs they would be forced to incur.

Cost-Benefit Analysis

We carried out a full cost-benefit analysis of the reform proposals. Like Ofgem, we have limited the overall assessment to costs within Great Britain (though we also record the costs reported by Irish respondents.) However, we do not accept Ofgem's view that certain costs can be ignored because they will not be passed through immediately to British consumers. Any proposal which increases inefficiency operates to the long-run detriment of consumers.

We calculate the benefits of the reform by reviewing Ofgem's Impact Assessment (IA). To We also circulated a questionnaire to industry players and other interested parties, asking for information on the benefits and cost to respondents arising from Mod 116 and its alternatives and variants.

Overall we found that Ofgem's IA overstates the benefits of the reforms and underestimates the costs. Compared with Ofgem, we conclude that the balance of costs and benefits is reversed, with the costs of Modification 116 outweighing the likely benefits. The net benefits of the proposed reforms (i.e. benefits *less* costs in present value terms) are shown in the table below.

The first row shows the net benefit of Mod 116A, which extends indefinitely the current "transitional arrangements". Respondents to our questionnaire indicated that they would incur some costs to implement this modification. We have imputed to Mod 116A (and to all other modifications) a benefit equal to these costs, as the value of removing regulatory risk or uncertainty by abolishing the "sunset clause". This adjustment does not change the ranking of the modifications, but Mod 116A has a net benefit equal to zero by definition.

The second and third rows show the *incremental* net benefit of adopting Mod 116C rather than Mod 116A (i.e. of long-term flat capacity booking), and Mod 116 rather than Mod 116C (i.e. of introducing flexibility capacity). The shaded fourth row shows the *total* cost of Mod 116, i.e. the sum of the incremental costs of individual reforms. The final row shows the incremental benefit of Mod 116B over Mod 116.

Net Benefit of Modification 116 and Alternatives

NPVs	Lowest Net Benefit Estimate	Highest Net Benefit Estimate
Incremental Net Benefit of Mod 116A Compared to Transitional Arrangements	£0.00m	£0.00m
Incremental Net Benefit of Mod 116C Compared to Mod 116A	-£33.04m	-£9.96m
Incremental Net Benefit of Mod 116 Compared to Mod 116C	-£80.59m	-£67.96m
Total Net Benefit of Implementing Mod 116 Compared to Transitional Arrangements	-£113.63m	-£77.91m
Incremental Net Benefit of Mod 116B Compared to Mod 116	£5.78m	£7.17m

Conclusions

We find that Mod 116A, which extends the transitional (current) arrangements indefinitely, has a net benefit of zero, the best of all these proposed modifications. Mod 116C, which introduces long-term booking of flat exit capacity (but not flexibility exit capacity), has a negative net benefit, but is the next best option. Mods 116 and 116B impose large net costs (compared with Mod 116C), due to the introduction of the flexibility capacity product.

Our analysis therefore implies that the costs of Mod 116, 116B and 116C significantly outweigh their benefits. It would be less costly to extend indefinitely the transitional arrangements as proposed by Mod 116A.

1. Introduction

Prior to the divestment by National Grid of the four Independent Distribution Networks (IDNs), Ofgem and National Grid consulted widely on possible reforms of NTS exit capacity charging arrangements. To date, the reforms of NTS offtake arrangements have been applied to exit capacity sold at NTS exit points serving Distribution Network Operators (DNOs).

Since the sale of the four IDNs, Ofgem has consulted further on extending the reforms of NTS offtake arrangements to cover Transmission Connected Customers (TCCs) as part of the Transmission Price Control Review (TPCR). Through the TPCR process, Ofgem and National Grid have consulted on and developed new business rules that define the proposed new exit regime. NGC has submitted the new rules as Modification 116 to the Uniform Network Code (UNC). Three signatories to the UNC have forwarded alternative modification proposals (Modifications 116A, 116C and 116B), which are to be considered alongside the core proposal (Mod 116). These alternatives have spawned a number of variants, as each of the modifications has been subject to scrutiny and refinement by experts.

The Gas Forum has commissioned NERA Economic Consulting to evaluate the economic case for the proposed reforms, encapsulated by Mod 116 and its alternatives and variants, in order to contribute to Ofgem's consultation process.

In order to evaluate the economic case for the proposed reforms, we first outline details of the UNC modification proposals:

§ In chapter 2 we describe current NTS offtake arrangements and the main characteristics of the four proposed modifications.

§ In chapter 3 we describe the proposed reforms in terms of the proposed exit capacity products and associated charging arrangements.

§ In chapter 4 we discuss the practical implications of Mod 116 and its variants, including some unintended consequences of the proposals.

Having described the proposed reforms of the NTS offtake arrangements, we discuss the economics of gas pipeline capacity, which informs our later appraisal of the proposals.

§ Chapter 5 discusses the cost structure of gas networks and the economics of gas network charges. The discussions are conducted with reference to the exit capacity products envisaged by Mod 116.

§ Chapter 6 discusses the incentives that the proposed reforms would provide through the exit capacity products they envisage. We pay particular attention to investment signals in this chapter.

§ Chapter 7 outlines some further consequences of the proposed reforms, namely the impact on the UNC modification proposals on security of energy supply, the impact on competition and the impact on trade between EU member states.

- Ofgem has suggested that the proposed reforms reduce the scope for NGC to "discriminate unduly" between users of the NTS in favour of the Retained Distribution Networks (RDNs). Chapter 8 evaluates the economics of undue discrimination and assesses the suggestion that the proposed reforms would reduce the scope for discriminatory behaviour by NGC.

Based on our description of the UNC modification proposals and the economics of gas pipeline capacity charging, in Appendix A we evaluate Ofgem's Regulatory Impact Assessment (RIA). The IA compares the case for introducing the enduring arrangements, which are envisaged by Mod 116, compared to the transitional arrangements, which are currently in place. The IA provides the basis for estimating the main quantifiable benefits of the proposed reforms.

Chapter 9 describes our own cost-benefit analysis of the reform proposals. The benefits we identify through our review of the Ofgem IA feed into this analysis and assist in identifying the benefits of the proposed reforms. To contribute further to our evaluation of the benefits arising from the proposed reforms and to enable us to measure the costs of implementing the reforms, we circulated a questionnaire to industry players and other interested parties. The questionnaire, shown in Appendix B, asked for quantified and descriptive information on the proposed benefits and cost implications for respondents arising from Mod 116 and its variants and alternatives. The conclusions of our cost-benefit analysis are reported in chapter 10.

Overall we find that Ofgem's IA overstates the benefits of the reforms and underestimates the costs. After reviewing both Ofgem's analysis and the responses to our questionnaire, we conclude that the balance is reversed, with the costs of Modification 116 outweighing the likely benefits.

2. Existing Arrangements and Proposed Reforms

This chapter outlines the existing "transitional arrangements" for NTS gas offtake and describes the approaches to reform which have been put forward by various members of the gas industry.

Ofgem and National Grid consulted widely on possible reform of NTS exit arrangements in the lead-up to the sale of the four Independent Distribution Networks (IDNs). Ofgem's Regulatory Impact Assessments (IAs) on offtake and interruptions arrangements in summer 2004 concluded that there was the need for market-based mechanisms to allocate NTS exit capacity, flow flexibility and interruption rights. However, to date, reforms have only covered NTS offtake arrangements for distribution network operators (DNOs). Ofgem consulted further on reform of NTS offtake arrangements during the Transmission Price Control Review (TPCR) and published a further draft IA in June 2006. The June 2006 IA compares the costs and benefits of the "enduring arrangements", which Ofgem hopes to implement, with the "transitional arrangements", which are currently in place.

2.1. Transitional Arrangements

Since 1 May 2005, National Grid has made exit capacity available on the basis of a Maximum Daily Quantity. The maximum hourly rate of offtake is 1/24th of the Maximum Daily Quantity. Network Exit Agreements (NExAs) define the limits on rates of change in flow.

The transitional arrangements created a new contractual interface between National Grid and the DNs and introduced two new products:

§ flat capacity (defined by a daily maximum offtake); and

§ flexibility capacity (measuring the amount of variation across the day).

The transitional arrangements introduce flat and flexibility capacity rights for DN Operators at NTS/DN exits, and a process for allocating this capacity. For NTS/DN exits, shippers pay exit capacity charges based on downstream capacity holdings.

The transitional arrangements did not extend these products and processes to shippers delivering gas from the NTS to Transmission Connected Customers (TCCs), i.e. to customers connected directly to the NTS, or Connected System Exit Points (CSEPs), which include interconnectors and Storage Connection Points. At such exit points, shippers must buy a single product, "NTS Exit Capacity", on behalf of their customers. At CSEPs, National Grid makes NTS Exit Capacity available on an interruptible basis on request and shippers book NTS Exit Capacity on a 12-month rolling basis, through a process that requires them to signal proactively any desire to renew their capacity rights. At other offtake points, capacity is booked automatically at the registered capacity of the supply point.

The transitional arrangements do not allow users to book existing capacity for periods beyond investment lead times. For incremental capacity and new connections National Grid extracts commitments from users through Advanced Reservation of Capacity Agreements (ARCAs).

2.2. Advanced Reservation of Capacity Agreements

Under the transitional arrangements, TCCs can rollover exit capacity which they hold on a monthly basis.[1] If the TCC requests additional exit capacity, then under the terms of National Grid's Incremental Exit Capacity Release (IEXCR) methodology statement, to the extent that the request requires capacity investment, an Advanced Reservation of Capacity Agreement (ARCA) must be agreed for the incremental capacity. ARCAs are intended to provide National Grid with certainty that new investment will be utilised. ARCAs are required where capacity investment involves providing new firm loads of 0.5mcm per day or more. ARCAs are also intended to give the party connecting to the NTS certainty that NTS exit capacity will be available going forward. If National Grid cannot agree the terms of an ARCA with the relevant party, then the dispute is referred to Ofgem.

In a recent dispute regarding an ARCA relating to the connection of the new Marchwood power station, Ofgem ruled that the ARCA between the TCC and National Grid should only last for one year. That is, the connecting party would pay exit capacity charges, irrespective of whether gas flows or not. Indeed, Ofgem states that it is generally "incumbent on National Grid to justify any additional level of commitment beyond one year",[2] which arises from Ofgas principles dating from 1997.[3] In evaluating the proposed terms of the Marchwood ARCA, Ofgem evaluated the risks involved in the investment, the level of financial commitment necessary and the efficient costs of the investment.

If the enduring arrangements are introduced, Ofgem envisages that there will be no need for the system of ARCAs, as users will be able to reserve capacity in an auction process. Ofgem anticipates that this process will give National Grid the necessary financial commitment to undertake efficient levels of investment. We discuss the validity of this expectation and the impact of Mod 116 on the process for the advanced booking of capacity in later chapters.

2.3. Proposed Modifications

In the last two years, Ofgem and National Grid have consulted on and developed new business rules that define a proposed new exit regime. NGC has submitted these new rules as Mod 116 to the Uniform Network Code (UNC). Three signatories to the UNC have forwarded alternative modification proposals (Mods 116A-C), which are to be considered alongside the core proposal (Mod 116). We summarise these proposals in the following subsections, in an order which best illustrates what each modification is intended to change, namely:

§ 116A (extension of existing arrangements);

§ 116C (long-term allocation of flat capacity);

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1 The following summary of ARCAs draws on *Determination By The Gas And Electricity Markets Authority Of A Dispute Under Section 27a Of The Gas Act 1986 Concerning The Terms Of An Advanced Reservation Of Capacity Agreement And The Charges Associated With The Proposed Connection Of A Power Station To The National Gas Transmission System*, Ofgem (undated): "*The Marchwood Determination*"

2 *The Marchwood Determination*, paragraph 7.12.

3 *A report on agreements made pursuant to the network code, including Advanced Reservation of Capacity Agreements*, Ofgas, 1997.

- 116 (long-term allocation of flat and flexible capacity);
- 116B (refinements of 116).

We are aware that UNC signatories have forwarded refinements to the above proposals. However, as the proposed refinements make no material changes to the nature or structure of the proposals, any differences are overlooked in our analysis. Note that

- we refer to Modification 116V and Modification 116VD as Mod 116;
- we refer to Modification 116BV as Mod 116B;
- we refer to Modification 116CV as Mod 116C; and
- where we refer to "Mod 116 and its alternatives and variants", we refer to Mods 116V, 116VD, 116A, 116BV and 116CV.

2.3.1. Modification 116A

Mod 116A proposes that the transitional arrangements currently in place should be continued indefinitely. Mod 116A achieves this aim by removing the "sunset clauses" currently in the UNC that limit the life of the transitional arrangements to 30 September 2010. The transitional arrangements would not therefore lapse after this date. Under Mod 116A, National Grid would continue to release and allocate exit capacity, through the transitional arrangements, far enough in advance to allow any physical expansion of the network necessary to match allocated exit capacity.

2.3.2. Modification 116C

The flat capacity product envisaged under the "enduring arrangements", defines the maximum quantity that may be taken over a day at an individual exit point. Under Mod 116, users requiring variable within-day flow rates would need to acquire both flat and flexibility capacity. However, Mod 116C proposes *only* the introduction of the flat capacity product.

The flat capacity product is common to Modifications 116C, 116 and 116B. Existing users would receive flat capacity initially on the basis of their "prevailing" bookings of NTS Exit Capacity. Where users make a sufficient commitment via the UNC process or an ARCA, National Grid would allocate additional flat capacity in annual blocks, without limit, for years beyond investment lead times. In shorter timescales, further capacity release programmes, constrained by the level of actual capacity, would operate through "pay as bid" auctions, first of annual capacity and later of daily capacity. The level of actual capacity (yet to be determined) would define the minimum "baseline" levels that National Grid had to release.

National Grid would cease to offer long-term interruptible NTS exit capacity and would only offer it on a day-ahead basis. Shippers wanting to secure long-term interruptible exit capacity would have to book "firm" flat capacity or buy interruptible capacity from another shipper. National Grid would also hold tenders to buy-back capacity in certain conditions (e.g. when the physical network was unable to deliver the anticipated gas flow). National Grid would facilitate capacity trading to enable shippers to transfer or assign capacity to other users at the same exit point.

Shippers would be exposed to overrun penalties only when total flows exceeded aggregate capacity holdings at an exit point, a rule intended to provide some protection against capacity hoarding. In effect, unused capacity held at an exit point would automatically be available to other users at no cost, as long as the total capacity held at the point exceeded demand for it.

2.3.3. Modification 116

Mod 116 suggests the introduction of both the flat and flexibility capacity products. The flat capacity product is the same as described above, for Mod 116C. The nature of the flexibility capacity product envisaged by Mod 116 is summarised below.

NGC does not consider it efficient to invest in providing flexibility capacity on the NTS, so this process is not intended to provide investment signals. Instead, NGC expects the limit on flexibility capacity to encourage users to ration more efficiently their use of the flexibility provided by linepack and system operations, i.e. to manage more efficiently their within-day gas offtake profiles. The volume of service required by a user is defined, as under the transitional arrangements for DNs, as (1) the cumulative quantity taken in the sixteen-hour period from 06:00 to 22:00 *less* (2) sixteen times the average hourly quantity for the gas day (06:00-06:00). The second of these amounts represents the quantity of gas that the shipper would have taken over the period from 06:00 to 22:00, if the daily quantity of gas had been taken at a constant rate throughout the day.

It is envisaged that the release, transfer and assignment of long-term flexibility capacity will be constrained by zonal, regional and national maxima. The release of shorter-term flexibility capacity will be limited to what is available, as with flat capacity. Likewise, National Grid will facilitate trading and will hold tenders to buy-back flexibility capacity as required for capacity management purposes.

Special rules would apply at bi-directional points, such as storage and interconnectors, to classify the point on a particular day as ***either*** entry ***or*** exit, based on measured aggregate gas flows. At multi-user exit points, appointed agents would need to allocate within-day gas flows to individual users, to determine their use of flexibility capacity.

2.3.4. Modification 116B

Like Mod 116, Mod 116B proposes the introduction of flat and flexibility capacity. However, it makes certain refinements to the nature of the products. The key differences between Mod 116 and Mod 116B are as follows.

§ When estimating a user's consumption of flexibility capacity, Mod 116B increases the tolerance of cumulative daily flow from 1.5% to 3%.

§ New NTS supply points and CSEPs commissioned between 01/07/2007 and the start of the enduring arrangements would secure initial "prevailing" NTS flat exit capacity based on the NTS exit capacity that they had registered.

§ Mod 116B distinguishes between release of incremental flat capacity and of flat capacity made available at existing exit points to slacken constraints imposed by the timetable for investment, effectively by allowing applications outside the July window and for start dates other than 1 October.

- Under Mod 116B, there would be no flexibility product commodity charge, but only an overrun charge, which would be triggered where (1) National Grid announces a "flexible constrained day" and (2), within a zone, where use of flexibility exceeds aggregate daily holdings on flexibility constrained days.
- If a user's flexibility utilisation increases as a result of an intertrip or forced outage, the overrun calculation will be based on that user's prevailing Individual Offtake Profile Notice (OPN) at the time the intertrip or forced outage commenced (rather than measured offtake).

The proposal also outlines requirements on National Grid to publish details of flexibility utilisation, overrun quantity and charges and expected flexibility utilisation.

2.4. Summary and Conclusions

The most significant changes prescribed by National Grid's plans for reform of the NTS offtake arrangements involve the creation of flat and flexibility exit capacity products for DCs, as well as DNs which must already purchase both products. For TCCs, the combination of flat and exit flexibility capacity products replaces the current system whereby users book firm capacity, giving them a right to offtake a certain amount of gas across the gas day, without a charge for flexibility capacity. Mod 116 to the UNC, proposed by National Grid, suggests these changes.

Three alternatives to Mod 116 have been put forward. They are best viewed as proceeding in the following order:

- Mod 116A, proposed by E.ON, suggests extending the transitional arrangements indefinitely;
- Mod 116C, proposed by Centrica, suggests the introduction of the flat capacity product, as under Mod 116, but not the flexibility capacity product; and
- Mod 116B, proposed by RWE, suggests the introduction of both flat and flexibility products, but with refinements compared to Mod 116.

3. Proposed Access and Charging Arrangements

This chapter outlines Mod 116 in terms of the products and the associated charging principles that it would introduce.[4] Currently, TCCs are able to flow gas at any desired rate or profile, provided the flow is lower than their booked MHQ and is within the notification and ramp rates for their offtake point. TCCs exceeding the MHQ incur overrun charges.

Under the enduring arrangements, envisaged by Mod 116, DNs and TCCs (or rather, their shippers) would secure their existing ("prevailing") capacity rights, but to acquire additional capacity, shippers would have to participate in auctions for forward purchases of capacity several years in advance.

3.1. Flat Capacity

Flat capacity purchases would allow users to offtake gas at a constant profile over the day. To avoid overrun charges, users would need to book flat capacity equal to their peak day usage, which for TCCs is equal to 24 times their peak hourly usage.

3.1.1. Booking arrangements

Whereas existing consumers automatically retain capacity rights by paying annual exit charges under current arrangements, under Mod 116 capacity which was not repurchased in advance auctions would be lost if desired by other users. However, in the short-term, users already holding exit capacity in 2007 would retain this capacity through a system of prevailing rights.

Then, each July beginning in 2007, holders could apply to increase their prevailing exit capacity, but only for gas years Y+4 to Y+7 (i.e. from October 2010 at the earliest). Holders could apply to reduce their prevailing capacity subject to a minimum advance notice defined by the longer of (a) four years after the last increase or (b) fourteen months (e.g. by giving notice in July 2009 to reduce capacity from October 2010). From 2007 onwards, NGC would also hold annual and daily auctions of exit capacity that is available but not already allocated to shippers.

3.1.2. Buy-back arrangements

On most gas days, users would hold more capacity than was needed. Parties holding excess flat capacity would be able to sell this back to National Grid if buy-back is required for balancing purposes, or to sell unwanted capacity to other users if it is required in day-ahead auctions. If National Grid notes that there is spare capacity, it can release this capacity in day-ahead auctions as flat capacity or as interruptible capacity.

In the period before investment can expand capacity, National Grid would sell uncommitted flat exit capacity through pay-as-bid auctions several years in advance of gas day in annual bundles of daily capacities. Beyond investment timescales, selling capacity in advance would

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[4] *DISCUSSION DOCUMENT: Modification Proposals to the Gas Transmission Transportation Charging Methodology (NTS GCD02* and *NTS GCD01)*, National Grid, 20th October 2006.

enable National Grid to secure some committed financial contribution towards the cost of expanding capacity where there is excess demand. National Grid would also offer firm and interruptible flat capacity in similar auctions, a day in advance.

3.2. Flat Capacity Charges: Two Options

National Grid has put forward two possible approaches for setting charges for NTS flat exit capacity. Both approaches outline methods for calculating prices for users holding prevailing (i.e. existing) rights and both outline methods for calculating reserve prices for flat exit capacity sold through auctions. Under each option:

§ a single flat capacity price would be calculated for each exit point for both DNs and TCCs;

§ flat capacity charges for prevailing rights would be based on long run marginal cost (LRMC), as defined in options one and two below, and capacity not covered by prevailing rights would be sold in auctions;

§ flat capacity charges would differ by node, rather than zone;

§ National Grid would determine flat capacity prices and auction reserve prices for all relevant gas years from a “single weighted average analysis of the ten year Supply & Demand forecast using the current Gas Year’s base model”.[5] However, this is a proposal for consultation and it is not yet clear how National Grid would apply this practice; and

§ a 100% flat capacity charge discount would apply to interruptible day-ahead capacity, as National Grid acknowledges that interruptible flat capacity use imposes no marginal cost on the network.

3.2.1. Flat Capacity Charging Methodology: Option 1

In option 1, National Grid would use a “transport model” to calculate the LRMC of relevant gas flows,[6] based on the premise that gas flows the minimum feasible distance from the relevant entry point to each “reference node,” and from each reference node to each relevant exit point. The LRMC includes incremental investment requirements and the incremental operational costs of gas flows for base case forecasts of 1-in-20 peak supply and demand in each relevant year.

In calculating LRMCs, the investment component would be based on the average cost of transmitting one peak day GWh of gas over one km for a given diameter of pipe. The average cost calculation would use data on previous pipeline expansions to estimate costs from the regression equation shown in the box below.

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5 *DISCUSSION DOCUMENT: Modification Proposals to the Gas Transmission Transportation Charging Methodology (NTS GCD01)*, National Grid, 20th October 2006.

6 *DISCUSSION DOCUMENT: Modification Proposals to the Gas Transmission Transportation Charging Methodology (NTS GCD01)*, National Grid, 20th October 2006.

Box 3.1
Average Cost Formula

Average Cost (£m/km) = a * (diameter in mm) + b * (1/length of pipe in km)

3.2.2. Flat Capacity Charging Methodology: Option 2

In option 2, National Grid would calculate flat exit capacity charges based on the existing Transcost model, with which National Grid calculates exit capacity charges at present on the basis of the LRMC of incremental gas flows over the network using a variant of the "panhandle" equations.[7] National Grid has described Transcost in previous publications (see National Grid website).

3.3. Flexibility Capacity: Availability and Charges

In order to vary their offtake across the day, users must also book flexibility capacity in annual bundles of daily rights in auctions years in advance of gas day, or book daily flexibility capacity in day-ahead auctions.

3.3.1. Availability of flexibility capacity

After analyzing the availability of flexibility capacity, National Grid concluded "there is no clear relationship between demand levels and inherent linepack availability".[8] Therefore, as flexibility availability is uncertain on any given day, to be sure of holding sufficient flexibility capacity to meet non-coincidental demand peaks, users would need to book their maximum flexibility needs in advance, which would lead to demand for flexibility exceeding the 22 mcm/day of flexibility which National Grid believes is available with certainty on the basis of network modeling for 2010/11.[9]

So far, the maximum utilisation of flexibility capacity on the NTS is only 15 mcm/day.[10] However, National Grid wishes to avoid any local overruns by making flexibility capacity available on a zonal and area basis. The national maximum of 22 mcm is therefore to be augmented by separate maxima for 4 "areas" (North = 9 mcm, Central = 8 mcm, West = 5 mcm and East = 8 mcm, making 30 mcm in total) and 17 "zones" (each with their own zonal maximum, summing to 40 mcm overall). National Grid has suggested that shippers may be able to exchange flexibility capacity between areas and zones, on the basis of "exchange rates", but has yet to publish any such rates.

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7 *DISCUSSION DOCUMENT: Modification Proposals to the Gas Transmission Transportation Charging Methodology (NTS GCD01)*, National Grid, 20th October 2006.

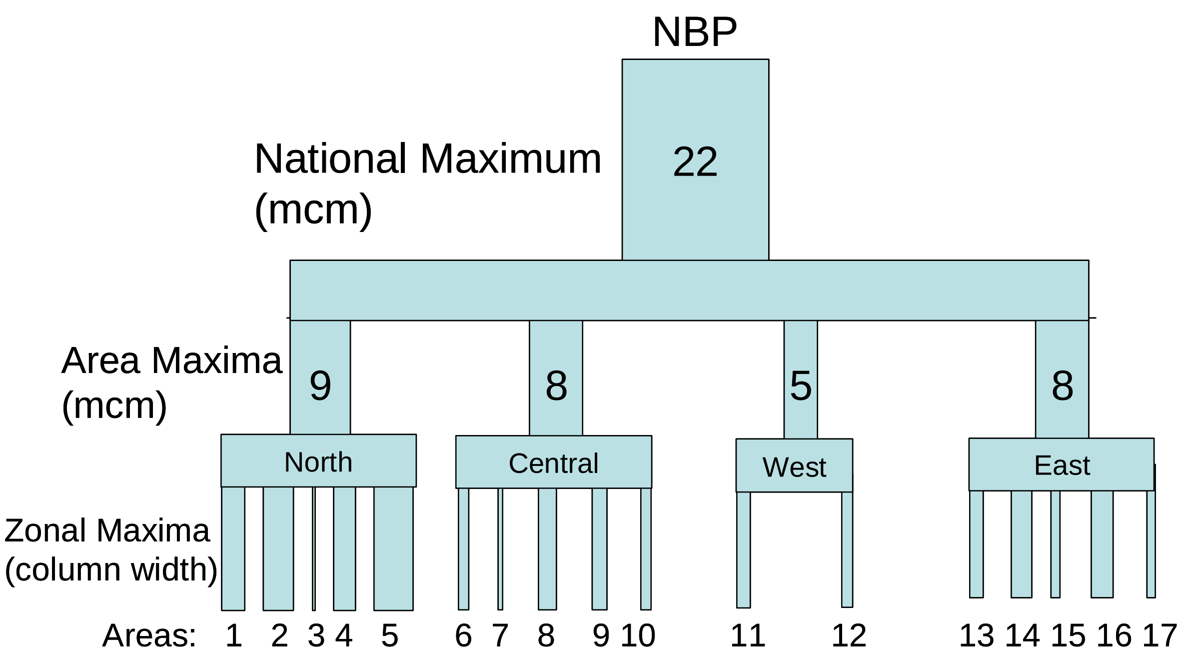
8 *DISCUSSION DOCUMENT: Modification Proposals to the Gas Transmission Transportation Charging Methodology*, National Grid, 20th October 2006.

9 *DISCUSSION DOCUMENT: Modification Proposals to the Gas Transmission Transportation Charging Methodology*, National Grid, 20th October 2006.

10 *NTS Exit Flexibility Capacity Definition*, EWOG, 28th June 2006.

This segregation of capacity by area and zone represents a move away from the simplest from of entry-exit system, in which capacities are defined for each entry and exit point, as if entry and exit point had a direct connection to the National Balancing Point. Instead of each exit point being connected directly to the NBP with a unique capacity, National Grid has defined a radial network structure for flexibility capacity, as shown in Figure 3.1. (Column widths indicate maximum capacity available at different levels.)

Figure 3.1
Allocation of Flexibility Capacity at National, Zonal and Area Levels



However, National Grid has not defined any similar network of flat capacities or any other capacity products. A similar development of the entry-exit model for flat, or even peak capacity, might well alleviate any of the concerns about potential excess demand for capacity, since it would enable National Grid to signal more constraints within the network.

3.3.2. Flexibility capacity charges

The flexibility capacity product would be sold in pay-as-bid auctions several years in advance of gas day or through submitting within-day Offtake Profile Notices (OPNs).

Under the enduring arrangements, shippers delivering gas to DNs and TCCs would have to book and pay for flexibility capacity to avoid overrun charges. The amount made available in advance auctions by NTS will reflect the amount of flexibility capacity which National Grid can make available without incremental investment (subject to an appropriate degree of certainty), since National Grid has stated it would not invest specifically to provide flexibility capacity provision. National Grid has assessed this amount to be 22 mcm/day, subject to area and zonal limits (see section 3.3).

National Grid's proposal describes an auction of exit flexibility capacity which rations something it considers a scarce resource (although maximum utilisation to date has fallen short of estimated availability of the service). In general, National Grid envisages setting a zero reserve price for annual and day-ahead auctions of exit flexibility capacity unless there are concerns regarding a lack of competition within a zone. Where competition is a concern, National Grid would set the reserve price (and therefore the most likely price) in line with an estimate of long run marginal cost (LRMC).

Within each zone, the local GDN is likely to dominate any auction. However, National Grid has not laid out how it would evaluate the extent of competition at an exit point, or how it would calculate the long run marginal cost of such a service.

3.3.3. Flexibility commodity charges

Once shippers have bought annual flexibility capacity, the buyer can use it on any gas day. National Grid wishes to charge shippers and DNOs a flexibility commodity charge to reflect the costs of using purchased flexibility capacity and to encourage the efficient use of it.

The flexibility capacity commodity charge would be defined as a user's daily flexibility quantity multiplied by the applicable flexibility commodity charge rate, where:

§ the daily flexibility quantity is defined as in section 2.3 as the user's offtake between 06:00 and 22:00 on a gas day, less 2/3 of the user's daily flat capacity holding, or zero if the daily flexibility quantity is calculated to be negative; and

§ the flexibility commodity charge rate would be 0.0343p/kWh, according to the cost allocation described in the box below. National Grid estimates the revenue from the flexibility capacity commodity charge would be £10.5 million per annum, were the charge to be applied in the 2006/07 financial year.

Box 3.2
NTS Cost Allocation Methodology: Assumptions

National Grid allocates to the use of exit flexibility capacity a share of its internal costs and of the costs of system reserve, shrinkage, and constrained LNG. The cost share is based on an assumption that the NTS will provide 776 mcm of flat exit capacity and 22 mcm of exit flexibility capacity.

National Grid attributes to flexibility capacity:

§ 2.8% = 22/(776+22) of internal costs, shrinkage costs and constrained LNG costs;

§ 22% = (22*R)/(776+22*R) of system reserve costs

R is set to 10 as National Grid believes that system reserve costs are driven by pressure loss, and assumes that gas flow using flexibility capacity cause 10 times more pressure loss than gas flows using flat capacity.

The results generated from this methodology are sensitive to National Grid's assumptions about cost drivers. National Grid assumes that internal costs, shrinkage costs and constrained LNG costs are proportional to mcm/day of flexibility capacity and flat capacity at the same rate, whilst using flexibility capacity incurs the costs of system reserve at 10 times the rate of using flat capacity. However, it is unclear whether use of flexibility capacity incurs any incremental or marginal cost, as linepack is a by-product of the capacity necessary to meet average daily – or average peak time – deliverability. The parameters used to allocate system reserve costs to exit flexibility capacity utilisation are not calculated transparently.

3.4. Summary and Conclusions

National Grid is proposing a system which departs from the usual principle of defining capacity requirements in terms of peak deliverability. The flat capacity product is similar to the current exit capacity, in that it defines daily average capacity over the day as a whole (06:00-06:00). However, National Grid is proposing to introduce a flexibility capacity product on the grounds that delivering more gas in a "peak" period (06:00-22:00) than over the day as a whole (06:00-06:00) uses an implicit intra-day storage service, principally from linepack.

National Grid proposes to limit the amount of this intra-day storage to 22 mcm, with the freedom to allocate this storage to areas and zones within the NTS being constrained by limits below the national level. This represents a departure from the usual entry-exit system, in which all exit capacity defines a single uniform right of access from the NBP to the exit point. National Grid is not proposing or investigating any such redefinition of access rights for flat capacity (even though similar constraints on flat capacity probably exist within the NTS).

The charging mechanism for flat capacity will be similar to the current one, being based on Transcost. Auctions of uncommitted flat capacity, made available in limited quantities in the period before investment can expand it, would set alternative prices and indicate where there was excess demand in the short term. National Grid would set reserve prices for all sales of flat capacity, based on a model of long run marginal costs. National Grid would only make interruptible capacity available by auction on a daily basis, but it would be exempt from any capacity charge. The arrangements for pricing flexibility capacity (apart from auctions) have yet to be defined, although National Grid envisages that reserve prices in auctions would normally be zero, as there would be no investment or long run marginal cost associated with expanding the volume of flexibility capacity (independently of flat capacity).

The proposals in Mod 116 therefore introduce two different aspects to the regime for reserving exit capacity:

§ A longer term scheme of reservation, intended to provide longer term investment signals;

§ An additional product of intra-day storage ("flexibility capacity") which GDNs and shippers must buy if they deliver gas to customers with a variable intra-day pattern of offtake.

4. Practical Implications of Mod 116

Mod 116 would have a number of practical implications for the way in which system users book and use capacity, and which are necessary for understanding the consequences for economic efficiency. The following sections describe some of these practical implications and draw conclusions on the source and nature of difficulties arising as a result.

4.1. The Agency Role of Shippers

One unintended consequence of Mod 116 relates to the transfer of capacity between shippers. Because TCCs can change shipper within a short period of notice relative to the timetable for advance booking of capacity under Mod 116, shippers which lose customers may be left with unneeded capacity at certain exit points.

Suppose a TCC, which is the only customer able to take gas at some given exit point (such as at a power station), wishes to change shipper. If the decision to change shipper takes effect quickly, the outgoing shipper may hold capacity which it no longer needs. Another shipper would then have to buy that capacity to serve the TCC. If it were unanticipated by either party, this situation would create a bi-lateral monopoly for the exchange of pre-booked exit capacity, and hence scope for opportunistic behaviour. Depending on the circumstances, the shipper which initially held the capacity may not recoup the cost of its capacity or the shipper buying the capacity may have to pay an excessive price for it (effectively ruling out any chance of taking over the customer).

To remove the risks associated with long-term financial commitment, shippers would have to change their contractual relationships with their customers (and also with the supplier if they are not the same business entity), in order to avoid such unanticipated bargaining situations. The shipper, the supplier and the customer would have to establish ***in advance*** a contractual mechanism for passing on the exit capacity to other shippers, if and when the customer and/or the supplier changes shipper.

4.2. Interruptability

At present, TCCs can opt for an interruptible capacity service, in which interruption can occur up to 45 days per year. Under Mod 116, National Grid would only release interruptible capacity day-ahead. Shippers holding firm flat capacity at one exit point could sell interruptible flat capacity to other shippers serving customers at the same exit point, on any timescale. For flexibility capacity, similar trading opportunities arise between exit points within the same “area” or “zone”, but no such arrangements apply to flat capacity.

4.2.1. Availability of interruptible service

Ofgem envisages that customers which are currently interruptible would, in most cases, buy firm capacity like all other users and sell any capacity back to National Grid if National Grid wishes to buy-back capacity. This approach would be the only one available to shippers wanting interruptible capacity at exit points with only one TCC. However, there is no guarantee that National Grid will (1) wish to buy-back capacity at the relevant exit point and (2) buy-back capacity from precisely those shippers serving customers who are currently interruptible, if buy-back is required.

4.2.2. Efficiency of interruptible services offered by National Grid

The economics of interruptibility are discussed in chapter 5. Customers with non-coincidental peak demands for gas (e.g. a firm customer and an interruptible customer) whose gas supplies share certain pipelines ought to be able to find a way to reduce their costs by paying only once for firm capacity.

However, the lack of transparency with which National Grid would select buy-back offers under the enduring arrangements generates uncertainty over how much of the cost of unwanted firm capacity could be recouped by customers who are currently interruptible. Moreover, if National Grid does not indicate zonal or area values of flat capacity, the entry-exit system hides the potential for such economic trades.

It has been suggested that National Grid could enter into contracts with users which would guarantee with some certainty that buy-back would be sought from contracted customers in preference to others. A contract of this nature would be a proxy for long-term interruptibility and would be particularly attractive to customers which are currently interruptible. The efficiency of such buy-back contracts hinges on National Grid's incentives. As flat capacity demanded by interruptible customers would push the level of flat exit capacity required above the level of firm capacity demanded currently, National Grid would either

- invest in flat capacity beyond that necessary to fulfil the needs of currently firm customers, which would reduce the likelihood of buy-back;
- buy-back flat capacity roughly equivalent to the offtake capacity that would be interrupted under current arrangements; or
- undertake some combination of the two.

Investment by National Grid to meet the flat capacity needs of currently interruptible customers would often be inefficient, as these customers do not currently impose incremental capital costs on National Grid, and may already have invested in back-up facilities (whose costs are now sunk). However, the efficiency of National Grid's decisions would depend on its regulatory incentives, to invest in exit capacity or to buy-back contracts, rather than on any purely market-driven decision-making process.

4.2.3. Efficiency of interruptions

In an emergency situation where there is a loss of NTS pressure, the current arrangements allow National Grid (1) to accept all buy-back offers, then (2) to interrupt interruptible customers and (3) only then, if the emergency persists, to interrupt firm customers (randomly). Under the enduring arrangements, if interruption is required, National Grid would have to resort to (randomly) interrupting customers (some of them "firm") at an earlier stage, if the volume of buy-back offers were not as large as the current volume of buy-back offers *plus* all interruptible customers.

4.3. Bi-directional Flows

At bidirectional entry/exit points such as storage facilities or interconnectors, there may be multiple shippers, who nominate their flows from and to the NTS. Currently, nominated flows are aggregated and the bi-directional point is operated in accordance with aggregated flow (e.g. exports through an interconnector are netted off from imports to define the need for entry or exit capacity). Under Mod 116, each shipper would be responsible for booking flat and flexibility capacity for gas offtake, but actual flows would remain dependent on the aggregated position of all the shippers. The precise accounting relationships have to be specified, but if shippers do not receive information on net flows at bidirectional sites, they may be left with the risk of an unintentional overrun, particularly for flexibility capacity.

Consider an example where there are two shippers at a bidirectional site. Shipper A takes gas with a flat profile (e.g. 100 units per hour) and has bought enough flat capacity (2400 units per day) to meet this requirement. Shipper B is sending 50 units per hour into the NTS and has purchased enough entry capacity. Net flows are only 50 units per hour of exit, so the shippers have between them bought excess exit capacity, since 1200 units per day would cover their needs. In this example, they require no flexibility capacity.

However, suppose that shipper B wishes part way through the day to stop sending gas into the network, to match the profile of a customer. The facility would still be a (net) exit point, but the (net) exit profile would no longer be flat. The variation in net exit flow caused by shipper B's decision would require shipper A to have some flexibility capacity. There would be no way to warn shipper A that it required flexible capacity, and the need would not arise from any change in its own pattern of usage. Shipper A might therefore incur overrun charges unknowingly.

In these conditions, shippers will not be able to plan their capacity requirements with any certainty due to their dependence on other players' actions. Moreover, it is not clear how the new charging systems should manage such a situation. Shipper B caused the variation in flow by adjusting its injection into the NTS to match a change in the offtake of its customer; it is hard to see how such behaviour uses diurnal storage, and yet nothing in this example indicates shipper A is using diurnal storage either.

4.4. Variation in Flows for System Balancing

Many users, not just storage facilities, can help to balance the system by taking less gas off at night than the user might wish, so that the system operator can use the gas left in the system to build up linepack. Under Mod 116, this service to the system would require the user to buy flexibility capacity, because of the variation in flow patterns, even though the variation is beneficial to the system. To avoid this perverse result, National Grid would have to develop a contractual mechanism that allowed such users (primarily, but not only, storage operators) to be exempt from flexibility charges in these circumstances.

4.5. Summary and Conclusions

The definitions of flat and flexibility capacity are set out in the modifications, but raise a number of questions about the nature of the technical problems that National Grid is trying to address. Flat capacity is defined as the exit capacity required for a constant flow rate over the day. However, part of National Grid's concern seems to relate in part to the maximum flow rate during the "peak" hours (06:00-22:00).[11] Another part seems to concern constraints

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[11] National Grid's proposal does not seem to indicate any need for hourly balancing, or to define and sell hourly linepack.

within the NTS, which emerge as rather restrictive limits on the availability of flexibility capacity at different levels (national, area and zone), but no similar geographical limits on flat capacity (other than at the exit point). The design of Mod 116 is therefore relatively complex, but does not consider a number of possible developments that reflect the economic cost structure of network capacity.

Despite the complexity of Mod 116, there will still be cases in which the rules generate perverse results and therefore create unnecessary risks or perverse incentives. Problems arise over:

- the ability to replace the interruptible service currently offered by National Grid with (discretionary) buy-back arrangements;
- the treatment of bi-directional connection points; and
- the treatment of users who vary gas flows in a way which helps to balance the system, but which incurs costs for flexibility capacity.

These difficulties will also increase the transactions costs of those required to participate in the system, principally shippers, but also storage operators, interconnector operators and TCCs.

The confusion arises out of the attempt to separate network capacity into abstract concepts of “entry” and “exit”, rather than specific locations linked by point-to-point capacity. Ofgem may believe that there are advantages in retaining the entry-exit system (e.g. in gas trading). However, it is necessary to accept that the system does not reflect the true cost structure of network capacity and therefore imposes some inefficiency which cannot be removed by creating yet more “entry-exit services”.

5. Economic Theory of Gas Network Charges

The preceding chapters have outlined the various proposals which have been forwarded for reforming the NTS offtake arrangements. This chapter discusses the economics of exit capacity charging. It also analyses the incentives for investment imposed by Mod 116 and the efficiency of the investment patterns which these incentives promote.

The discussions of the economics of exit capacity charging will inform our analysis in chapter 6 of the incentive effects of Mod 116, and our discussion of potential costs and benefits of Mod 116 in chapter 9 and in Appendix A.

5.1. The Economics of Gas Network Costs

At present, TCCs can acquire either "firm access" or "interruptible access".[12] Customers holding "firm access" rights are able to take gas at any time (up to the level of their capacity holding), whereas interruptible customers agree to have their service restricted or completely curtailed in certain conditions.[13] Interruptible customers include medium-to-large industrial and commercial sites, many of which possess standby fuel and other equipment to allow continued production when their gas supply is restricted.

5.1.1. Pipeline usage and cost drivers

When National Grid plans the size of the transmission network to meet its "1-in-20" peak day obligation, it does not include the peak capacity required for the interruptible customers as it assumes that they can be interrupted during peak periods. A stylized representation of the capacity and usage of gas pipelines – when access to the network can be either firm or interruptible – is shown in Figure 5.1.

This diagram shows the pattern of usage over a year as a whole for a defined piece of pipeline capacity, with the days of the year arranged from left to right *in descending order of demand*. On the left, firm users are using the full capacity of the pipeline for 20 days (a purely illustrative figure), but on other days of the year they use less than the full capacity. Therefore, on those other days, spare capacity can be used by others, on condition that they interrupt their usage when the firm users need it.

Interruptible demand (the shaded area) is interrupted, in this example, between 20 and 45 days a year, to make space available for firm customers. Different users may be interrupted for different numbers of days within a year, but none requires the pipeline company to build any capacity on its behalf.

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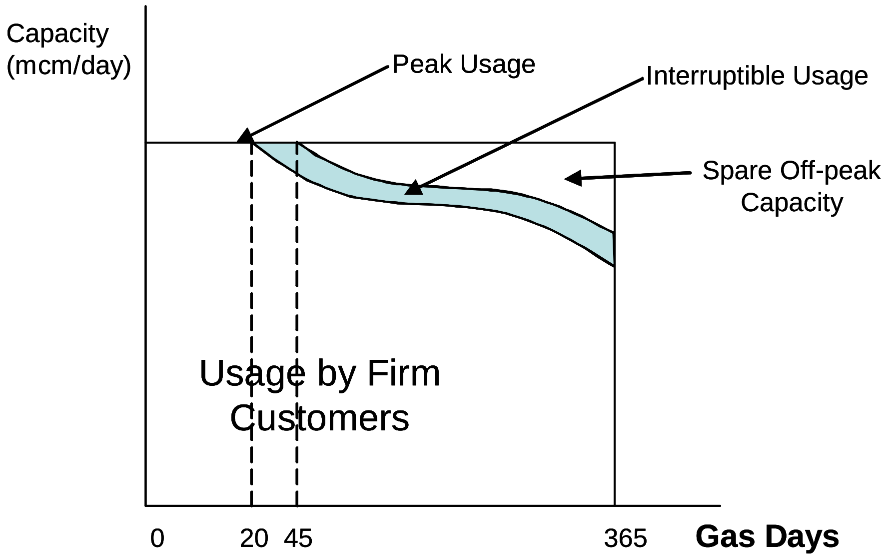
12 Supply points which consume above 5,860 MWh p.a. and are able to stop offtaking gas within the five hour contractual notice period may request interruptible transportation arrangements. National Grid is then obliged to give "interruptible status" to such supply points "on-demand", even though it may not require the supply point to be interruptible.

13 National Grid may restrict gas supply in the event of network capacity constraints, supply-demand balancing on high-demand days, in an emergency or for testing purposes.

Figure 5.1
Interruptible / Firm Customer Usage Patterns



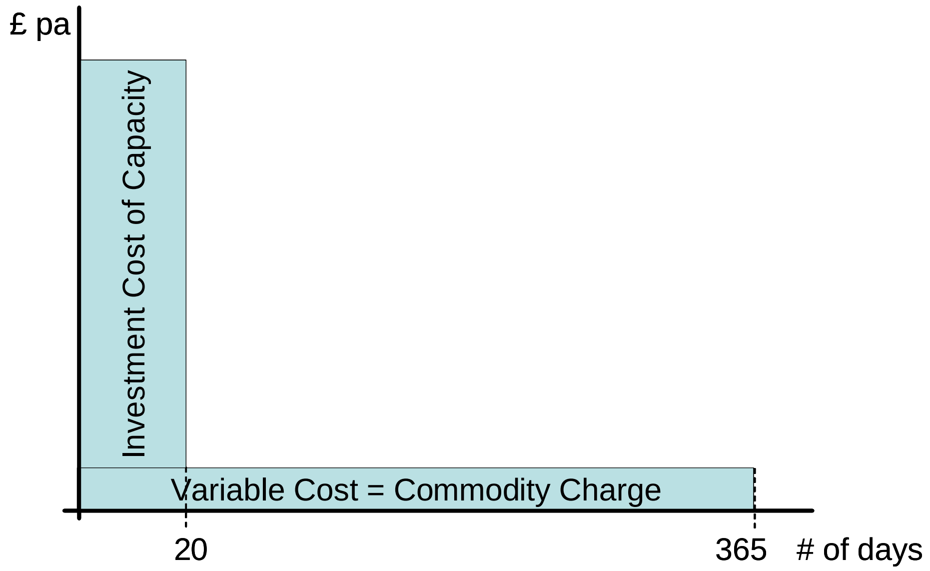
Up to 20 days a year, the pipeline is fully utilised by customers willing to pay the cost of capacity in order to secure firm (i.e. guaranteed) access. In the 25 days between day 20 and day 45, some capacity is unused by firm customers and available for use by interruptible customers. There is no additional cost associated with making this capacity available (although there might be excess demand for it from interruptible customers, such that it would have a positive value if it could be sold in a secondary market for capacity). In practice, there is limited scope for trading exit capacity within National Grid's system since, under the entry-exit system, exit capacity is specific to an exit point at which the number of users may be very small. These users cannot therefore trade the part of their exit capacity which uses a congested route that serves many exit points.

Outside the 45 days of peak demand, there is always some spare capacity available at no extra cost (apart from the variable cost of moving gas), so capacity has zero value.

5.1.2. Cost structure of pipeline capacity

Figure 5.2 shows the implication of this pattern of usage for the costs of a gas pipeline or network. The costs of building capacity are incurred to meet the peak demand of firm users. The cost of off-peak usage amounts only to the variable costs of operating pipelines (i.e. the cost of compression and other operating costs). Interruptible users do not impose any cost for building capacity because, whenever capacity is fully used, their demand is interrupted.

Figure 5.2:
Cost Structure of a Gas Pipeline



Accordingly, the charging regime for shippers supplying gas to supply points connected to National Grid's network varies by type of access (i.e. firm or interruptible).

- Anyone who ships gas from the beachhead to *firm* supply points pays entry capacity charges, exit capacity charges and commodity charges.
- Anyone who ships gas from the beachhead to *interruptible* supply points pays only the entry charge and exit commodity charges.[14]

5.2. The Economics of Flat Capacity

Under current arrangements, firm TCCs (or rather, their shippers) pay for capacity which allows them at all times to take a certain volume of gas over a gas day. *In practice*, we understand, National Grid requires firm TCCs to pay for the capacity required to deliver their maximum hourly quantity, multiplied by 24. Thus, in practice, TCCs pay a capacity charge for their *maximum* hourly deliverability.

Under Mod 116, all users will have to book flat capacity, which gives users the right to take a certain volume of gas at a constant *average* rate over each gas day. Therefore, all users will have to pay exit capacity and commodity charges for taking gas from the NTS. Users who are currently "firm" would book flat capacity equal to their current ("prevailing") firm capacity holding, but in practice they may book less, if their average daily offtake on peak days is less than their maximum hourly quantity.

Users who are currently "interruptible" would also have to book a quantity of flat capacity up to their current interruptible capacity holding. They may book less, in order to avoid capacity

[14] Additionally, supply points nominated by National Grid to be interrupted for more than 15 days in a particular year (up to maximum permitted which is usually 45 days) receive a transportation charge credit.

charges, or in anticipation of buying some interruptible capacity on a daily basis, but they will most likely book a positive amount in advance.

A problem arises over those interruptible customers who have undertaken investments to accommodate the possibility of interruption which are now sunk, such as investment in back-up fuel facilities at power stations. Given that these investments are sunk, investment to provide these customers with firm exit capacity is inefficient. However, under the proposal, some of these users would have no way to buy interruptible contracts on a long-term basis.

Currently, National Grid offers interruptible contracts on demand. In an ideal system, such contracts might be available in a secondary market from other users. However, many TCCs are the sole occupant of their exit point. The entry-exit definition of capacity does not permit trades with holders of capacity at other exit points (except via some system of non-transparent “exchange rates” set by National Grid). Thus, Mod 116 abolishes the only possible source of long-term interruptible contracts, leaving a hole in the market that may cause inefficiency.

This analysis of the economics of capacity refutes the claim that interruptible users are “free riding” on firm users, since their charges reflect the fact that they impose no costs of building capacity. It also suggests that there would be a loss of efficiency from removing TCCs’ access to long-term interruptible capacity under the firm-only capacity arrangements envisaged by Mod 116.

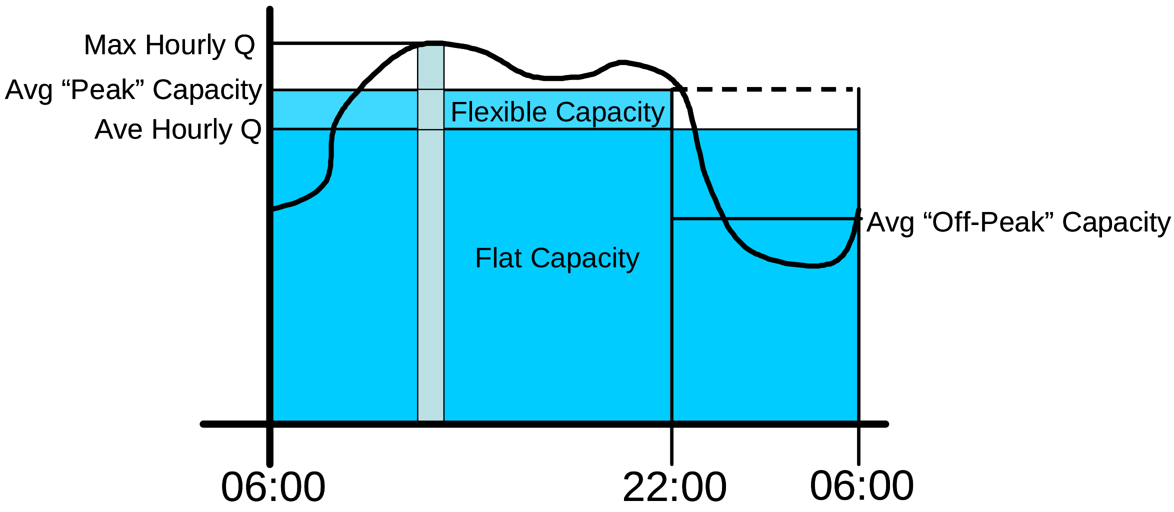
5.3. The Economics of Flexibility Capacity

Mod 116 would introduce a new flexibility exit capacity product. Flat exit capacity would in future allow the holder to take a certain volume of gas at a constant rate across the gas day. Users would require exit flexibility capacity to take gas at a higher average hourly rate before 22:00 than afterwards.

5.3.1. The nature of the service

To illustrate the nature of flexibility capacity, which is provided predominantly through linepack and diurnal storage, we show in Figure 5.3 a possible profile of NTS offtake requirements during a gas day. Figure 5.3 shows the pattern of daily usage during one of the peak 20 days within the year for a defined piece of pipeline capacity, with the hours in day arranged from left to right in *chronological* order from 06:00 at the start of the gas day to 06:00 at the end of it. The height of any point represents a value in mcm/hour (or MW), whereas areas represent mcm or mcm/day (or MWh or MWh per day).

Figure 5.3
Illustration of the Flexibility Product



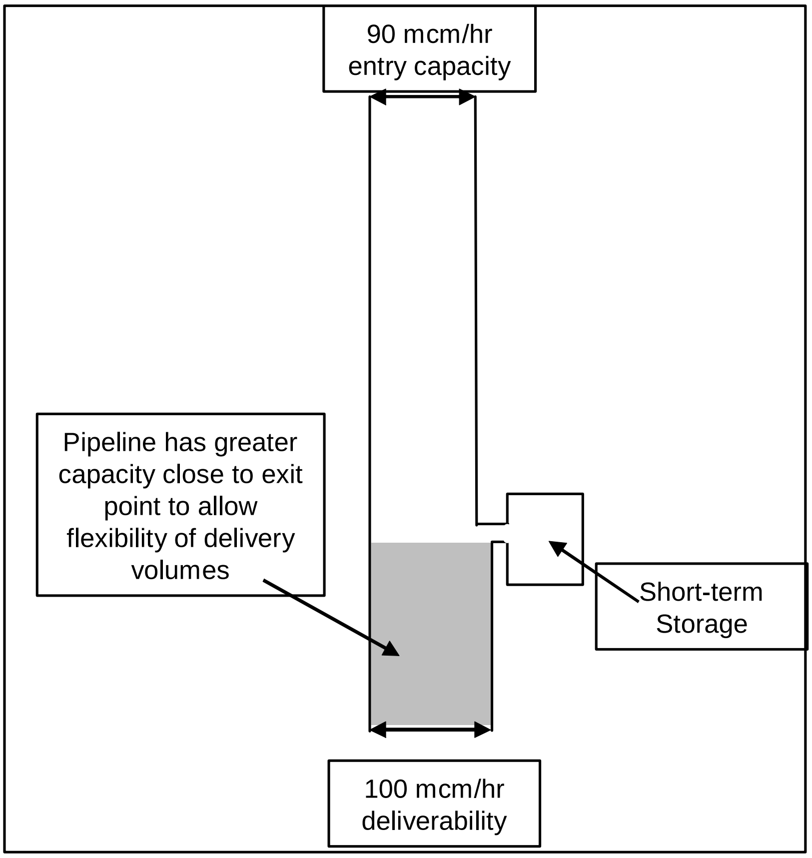
The curved line shows gas offtake over this period, the average level of which (Ave Hourly Q) is shown as a horizontal line. The vertical column shows the maximum hourly quantity (also known as Standard Hourly Quantity or SOQ).

According to Mod 116, this user would need to contract for an amount of flat capacity (in MWh/day or equivalent units) defined by the large plain coloured rectangle. The user's requirement for flexibility capacity is derived by comparing this level with average offtake over the "peak" period within the day (06:00-22:00). The difference between this "average peak capacity" and flat capacity for this peak period represents the requirement for flexibility capacity (cross-hatched area).

Closer investigation of the formulae reveals that flexibility capacity is effectively the deliverability or withdrawal capacity of a storage product, namely the storage or linepack that can be filled up using off-peak flat capacity not required to meet the user's demand in off-peak periods. Hence, the model requires users to pay National Grid for using linepack and gas held in diurnal storage within the NTS. When offtake demand is below average offtake, National Grid replenishes linepack and gas in diurnal storage.

A schematic depiction of how diurnal storage and linepack allow National Grid to accommodate higher offtake in peak periods is shown in Figure 5.4 below. The figure shows a pipeline which has a capacity of 90 mcm/hour for most of its length. At some point, the pipeline is connected to a storage facility; beyond that point, its capacity rises to 100 mcm/hour.

Figure 5.4
Schematic Illustration of Flexibility Provision Infrastructure



In this example, the pipeline can sustain 100 mcm/hr of offtake for short periods despite the long-term offtake capacity being limited to 90 mcm/hr, by filling and depleting the storage facility. (Under Mod 116, the charge for flexibility capacity assumes that the user first depletes the storage over the period 06:00-22:00) and then replenishes it over the period 22:00-06:00, but the effect is similar.) Suppose the user maintains a constant rate of injection of 90 mcm/hour over the whole day, but took 100 mcm/hour during the 16-hour peak period, with demand over the 8-hour off-peak period being only 70 mcm/hour. The amount flowing into storage off-peak would be 160 mcm (= (90-70) * 8 mcm), which would match the amount flowing over of storage over the peak period (= (100-90) * 16 mcm).

In this case, the user would have to book daily flat capacity of 2160 mcm, equivalent to deliverability of 90 mcm/hour, and daily flexibility capacity of 160 mcm, equivalent to peak time (16-hour) deliverability of 10 mcm/hour. Thus, altogether, the user would have booked flat and flexible capacity of 100 mcm/hour.

The total cost of providing this rate of deliverability over and above 90 mcm/hour (i.e. the cost of flexibility capacity) would depend on the amount of pipeline with a capacity of 100 mcm/hour, and the cost of line pack or diurnal storage (if any). Such costs could only be calculated if it were possible to break down the network into sub-segments as in Figure 5.4.

5.4. The Costs and Choices Related to Flexibility Capacity

In principle, the pipeline company can always decide to provide offtake capacity either by expanding the whole of the pipeline to the point where its overall offtake capacity is 100 mcm/hour, or by installing more storage near to the customer's exit point (provided there is unused capacity for replenishing the storage). Users can choose to manage without National Grid's storage by taking gas at a flat rate, but they cannot make similar choices over upstream investments in the NTS.

5.4.1. Restrictions on investment options

Under Mod 116, only National Grid can provide the storage facility that would enable the variation in offtake up to the peak level of 100 mcm. Because the definition of flat exit capacity comprises one piece of capacity linking the NBP to the exit point, National Grid provides the user with no indication as to where the constraint lies. The user cannot therefore compete with National Grid's demand for payment for diurnal storage by connecting alternative storage facilities to the NTS.

The user might also reduce its use of linepack or diurnal storage by varying the rate at which it injects gas *into* the pipeline, a technique adopted in some parts of the United States. However, users of the NTS cannot use their upstream access to swing gas in order to limit use of linepack or diurnal storage, since entry capacity is not subject to a similar regime of measuring flow rates over the peak period (06:00-22:00) separately from flow rates over the off-peak period (22:00-06:00). Users would therefore receive no offsetting credit for varying their injections in line with their offtakes.

This inability of users to choose to invest in supporting facilities connected to the NTS, or to manage their gas injections in a different way, means that in practice National Grid has a monopoly over such decisions. To avoid paying for flexibility capacity, users can only invest in facilities within their own sites which reduce the variability of their offtake from the NTS.

5.4.2. Lack of locational signals

The proposed flat capacity product does not reflect the capacity of the pipeline in Figure 5.4 at either end. Instead, it represents an average rate of offtake, weighted by the duration of different periods. In practice, gas pipelines and networks show a variety of capacity values over different stretches. The most efficient signal would recognise that capacity varied between different points on the network by dividing a pipeline into different segments, or by dividing exit capacity on the network into different areas or zones, much as National Grid has proposed to do for flexibility capacity. The ability to use linepack within each of these settlements would then be a relatively simple question of engineering standards.

However, under Mod 116 as applied to National Grid's entry-exit system, it is not clear whether the area and zonal constraints on flexibility capacity reflect only the amount of linepack, or whether they also implicitly contain information about (peak) capacity constraints within the network. This potential confusion of signals would not be conducive to efficient decisions by users. For instance, because it lacks a real locational element, the entry-exit system provides no signal as to where users should invest in storage to avoid the costs of pipeline construction.[15]

5.4.3. Conditions for efficient signals

The pipeline company might receive better signals about investment needs by separating the current definition of exit capacity into flat and flexibility products:

(a) if the pipeline company has a choice over whether to expand pipeline capacity or to install more diurnal storage; and

(b) if the capacity of diurnal storage is constrained or

(c) if the capacity of diurnal storage has a separately identifiable cost.

In practice, none of these conditions appears to hold within the NTS, since according to National Grid:

(a) National Grid has a policy of investing to meet peak time deliverability (effectively the maximum hourly quantity or average "peak" capacity) and has stated that it would not normally invest to provide flexibility (i.e. a diurnal storage product);

(b) usage of flexibility capacity has never come close to the level available at the national level; and

(c) flexibility capacity (diurnal storage) comes free as a by-product of investment in peak deliverability.

It is therefore difficult to understand the rationale behind the decision to divide the downstream level of maximum deliverability (100 mcm/hour in our example) into (1) the average rate of deliverability and (2) a withdrawal from diurnal storage during the peak period. We are not aware of any other transmission network that has tried to divide entry or exit capacity like this.[16] The flexibility provided by such means is simply a by-product of the capacity built to meet users' needs and therefore they pay the cost of the flexibility if they pay the cost of the capacity. The extent of such flexibility is essentially an engineering question, rather than a commercial choice.

Furthermore, we note from National Grid's analyses of the availability of flexibility capacity that "there is no clear relationship between demand levels and inherent linepack availability Figure 5.3."[17] Therefore, we infer that peak average daily offtake requirements do not coincide with peak flexibility requirements. In terms of Figure 5.4, the upstream capacity might allow peak demand to be met without using all the available storage. Although the

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[15] This lack of locational signals is a general problem for investment in storage with Great Britain and is not confined to the difficulties that flexibility capacity would cause.

[16] Some gas networks, such as the Dutch one, offer the equivalent of inter-hourly storage, but in the context of hourly metering; the equivalent in a daily metered system would be inter-daily storage. Some US gas pipelines have created charges for line pack, but within system which defines capacity on a zonal or point-to-point basis, so that users can see where they should locate competing forms of storage, or can use gas swing as an alternative to linepack.

[17] Quote Source: ***DISCUSSION DOCUMENT: Modification Proposals to the Gas Transmission Transportation Charging Methodology***, National Grid, 20th October 2006.

engineering conditions may be more complex than shown in our figure, the need to ration linepack by charging for it is far from clear.

Indeed, in terms of Figure 5.4, National Grid benefits from users not having a flat profile of usage (at, say, 100 mcm/day), as the lower usage during off-peak hours allows the pipeline operator to reduce the size of the upstream pipeline and instead to build up the pressure required for delivery during the peak periods. To be able to follow this procedure, the system operator needs customers to reduce their offtake in the "off-peak" period (22:00-06:00 in National Grid's modification). Hence, a decision by users to react to a charge for flexibility by switching to a flat profile of delivery might cause National Grid some problems.

5.5. Summary of the Economics of Capacity

Figure 5.4 shows the way towards a possible solution to the conundrum that a flat profile of usage would cost more than one which allowed National Grid to replenish linepack. The pipeline shown in Figure 5.4 does not have a uniquely defined capacity. At one end, its capacity is 90 mcm/day and only near the exit point does it rise to 100 mcm/day. In between lies the capacity of the "storage facility" represented by linepack. Efficient use of such a pipeline would require National Grid to define explicitly all three capacities in its service offering.

In fact, as explained in section 3.3, National Grid has already broken down the availability of *flexibility* capacity (i.e. diurnal storage) by "zone" and "area", such that upstream capacities are defined separately from downstream capacities. It is a short-coming of the proposed Modification 116 (and all variants on this topic) that National Grid has not offered a similar breakdown of peak or flat capacity. It is not even clear whether the area and zonal maxima imposed on flexibility capacity represent local diurnal storage capacities or some mixture of national storage capacities and local constraints on the capacity of pipelines linking them to users. Defining capacity at different points in the NTS would allow National Grid to signal the existence of real constraints, whereas figures for flexibility capacity can only hint at pipeline or network constraints and may actually hide them (since constrains on flexibility – i.e. on the use of storage – may bite at different times).

6. Incentives Provided by Mod 116

Supporters of the “enduring arrangements” (Mod 116) maintain that it will improve efficiency. The analysis above suggests that such claims are highly dubious, as explained in the following sections.

6.1. Auctions, Reserve Prices and Tariffs

Any description of Mod 116 and its alternatives and variants will contain a detailed discussion of the auctions by which National Grid hopes to allocate capacity. However, in practice, these market mechanisms may be less important than National Grid’s regulated interventions.

In a great many cases, unrestricted auctions will be infeasible or unacceptable. For instance, at exit points where only one user requires flat capacity, it will not be possible to hold a meaningful auction. Auctions cannot provide signals to invest in new exit points, where there are no existing users, a problem that has already arisen over the addition of an entry point at Milford Haven. Also, if flexibility capacity is in excess supply, an auction may produce a zero price, in which case National Grid will impose reserve prices based on a tariff model that has yet to be specified. Finally, although National Grid has offered to make spare (“interruptible”) capacity available on a daily basis, frequent auctions of such capacity at low prices will encourage shippers to migrate to this market, which will undermine National Grid’s revenues. National Grid has already signaled a desire to limit such outcomes in entry capacity auctions, by imposing reserve prices on the auction of daily entry capacity.[18]

In these cases, any incentives will depend upon the reserve prices set by National Grid, making them equivalent to tariffs. Unfortunately, National Grid has so far proven unable to say how capacity charges for flexibility capacity should be said, or how the introduction of flexibility capacity should change capacity charges for flat capacity. National Grid’s policy on buying back capacity from interruptible users is also a source of uncertainty. In practice, therefore, Mod 116 and its variants are subject to major risk and provide little transparency over pricing methods.

6.2. Investment Signals

We have discussed above how the entry-exit system hides true signals about the costs of locating different facilities at different locations within the network. In practice, therefore, users will not receive efficient signals about alternative investment opportunities.

The replacement of National Grid’s interruptible service with a daily allocation will not substitute for secondary trading in spare capacity. As a result, unless users can rely on a steady stream of low cost daily interruptible capacity (which would cause problems for National Grid), they will be constrained to use firm capacity and will have no guarantee of being able to sell it back to National Grid. The lack of a secondary market for interruptible capacity may encourage or oblige users to rely more heavily, but not necessarily more efficiently, on the NTS for capacity.

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[18] Platts Commodity News, 26/10/06.

National Grid's investment policy will be unaffected by the reforms, since it will continue to be guided by the 1-in-20 obligation to meet peak demand, which means that it will continue to rely on National Grid's own interpretation of shipper demands. However, under the proposed reforms, some users who are currently content to take interruptible capacity, because they have back-up fuels on site, will in future have to book firm capacity. If National Grid mistakes such requests for capacity as statements of firm demand, applying its 1-in-20 standard will lead to additional and unnecessary investment.

Similarly, with regard to flexibility capacity, National Grid has set out its determination to follow a particular policy regardless of price signals emerging from auctions:

> *"It is… assumed moving forward that it is more efficient and economic for DNs to invest on their own networks for … diurnal requirements. Users will therefore not be able to bid for NTS Exit (Flexibility) Capacity above existing capability levels in the annual auctions and thereby trigger investment specifically to release additional NTS Exit (Flexibility) Capacity.…On the basis that investments have historically been for end of day requirements and this will continue into the future, National Grid NTS considers that NTS investment costs should be related to NTS Exit (Flat) Capacity charges only."*[19]

National Grid therefore has no intention of investing in flexibility on its own network, so even if flexibility capacity is in short supply (which appears to be unlikely), any price signals emerging from auctions would not give National Grid useful incentives. Since GDNs will dominate the exit points, zones and areas where they are attached, it is likely that any signals emerging from their booking of flexibility capacity will be driven by National Grid's reserve prices, rather than any market signal. The reserve prices will be no more transparent, and will encourage no greater efficiency, than the quantitative limits contained at present in ARCAs and NExAs. Indeed, these prices may be even less transparent or predictable, if they emerge from a cost model than relies on many subjective assumptions.

Hence, the claims for greater efficiency in investment appear to be dubious, or even unfounded.

6.3. Level of Flexibility Capacity

National Grid has defined the level of flexibility capacity to be made available to the market as 22 mcm. However, even the analysis that produced this figure[20] also showed that the level might be anything from 26 to 34 mcm in equivalent conditions ("D50" or "D150") depending on the scenario modelled. National Grid has taken the view that the adopted level should be available in nearly all conditions. However, this decision means that the figure of 22 mcm is an artificial constraint in nearly all conditions, somewhat lower than the actual figure. Should any signals emerge from auctions of this flexibility capacity, they will reflect this artificial

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19 *DISCUSSION DOCUMENT: Modification Proposals to the Gas Transmission Transportation Charging Methodology (NTS GCD02)*, National Grid, 20th October 2006. Paragraph 3.3-3.4.

20 National Grid (2003a), NTS Exit Flexibility Capacity Definition, EOWG, 28 June 2003.

scarcity and will not therefore indicate grounds for investment in flexibility capacity, even if National Grid were to change its investment policy.

6.4. Advanced Commitments to Purchase Capacity

A key aspect of the proposed modifications (except 116A) is the adoption of longer term commitments. Some longer term commitments will provide very strong incentives for efficient use of capital, particularly commitments by users to pay the full incremental cost of capacity over the life of the assets and commitments by pipeline companies to provide the full and accurate amount of capacity created by those assets. However, all the proposed modifications fall someway short of these long-term commitments and it is not clear whether the extension of the existing short-term commitments will greatly improve investment signals.

One argument which has been put forward for the reform of the NTS exit arrangements is that National Grid requires stronger financial guarantees in order to invest in new capacity to meet new or increased demand for exit capacity. That is, National Grid claims that under the current system of ARCAs, it faces a risk of the user reducing its demand after the ARCA expires, leaving National Grid with more capacity than it can sell. National Grid claims that releasing flat exit capacity for auction further in advance would give a stronger financial commitment, thereby reducing the risks it faces and improving the efficiency of investment signals. However, this argument has serious weaknesses.

Firstly, the argument is redundant when applied to the advanced reservation of exit flexibility capacity as National Grid has no intention of investing to increase flexibility capacity. Secondly, the current system of ARCAs allows the reservation of firm exit capacity in advance of investment lead times at TCCs. National Grid has not provided any evidence of which we are aware that TCC demand for NTS exit capacity falls significantly following the expiry of the ARCA, thereby leaving National Grid's new investment in exit capacity partially unsold. In these cases, such as the connection of a new gas-fired power station, for example, the end-user that requires access to the NTS has considerable sunk costs in its own assets. The sunk capital investment means that the owner of the assets has little incentive to remove them in the future, and will continue to buy NTS capacity for many years into the future. For instance, despite the variation in electricity and gas prices, Ofgem considers the demand for exit capacity from gas-fired power stations to be relatively stable and predictable.[21]

It is therefore doubtful whether extending the duration of commitments from a year (the maximum following the Marchwood decision) to several years (under Mod 116) will actually change either investors' degree of commitment to use exit capacity or the strength of the investment signals such commitments provide to National Grid.

6.5. Firm versus Interruptible Capacity

National Grid may prefer a system that commits users to buy firm, rather than interruptible capacity, so that they cannot avoid costs by becoming interruptible. Longer term commitments to buy firm capacity would remove the possibility of users buying firm

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[21] See *The Marchwood Decision*, Ofgem, 2006.

capacity for a year or two, encouraging National Grid to invest in the capacity needed to meet their peak demand, and then switching to interruptible capacity – safe in the knowledge that they will never be cut off. The removal of such possibilities will discourage some inefficient connections, i.e. users who would not be prepared to pay the full costs of providing firm capacity.

However, as discussed above, some users may genuinely wish to acquire interruptible capacity and will not be able to do so, except on a daily basis from National Grid, because exit capacity cannot be unbundled into tradable segments over different parts of the network. The lack of such a interruptible service may discourage connections in potentially efficient cases, i.e. where users would be willing to pay for the local ("shallow") connection, but would then wish only to use low cost spare (interruptible) capacity higher up the network.

6.6. Costs of Arbitration

Once investment is sunk in both the TCC's assets and National Grid's capacity at a particular exit point, there would be a problem of bilateral monopoly at this location. In any subsequent bargaining process, there are liable to be disputes and a need for arbitration by Ofgem in some cases. Ofgem and National Grid may hope to reduce or eliminate the need for such arbitration by allocating capacity through auctions. However, the lack of transparency in the allocation and charging methodologies (including the volume and price of capacity buy-backs) creates scope for National Grid to exercise discretion and hence for disputes to arise anyway.[22]

6.7. Summary and Conclusions

The proposed modifications continue to operate within an entry-exit regime with commitments that are longer than at present, but which still do not represent a commitment to pay the full cost of investment or to provide the full amount of capacity created by it. As a result, National Grid appears to be determined that the modifications will not change its investment policy and may not even affect its individual investment decisions.

The entry-exit also creates uncertainty over what capacity is available, particularly the rather abstract flexibility capacity. National Grid has therefore restricted the level of flexibility capacity to that which will be available in nearly all conditions, implying that there will be an artificial scarcity in nearly all conditions. Moreover, the entry-exit system offers no scope for breaking down flat capacity into different segments, so that users can hold some (dedicated to their needs) on a firm basis, and acquire the remainder on an interruptible basis.

These deficiencies in the scheme put in doubt the supposed benefits of efficient investment that may result from the proposed modifications. Indeed, some aspects of the proposals may encourage more inefficient decisions and impose higher costs on the system and on consumers.

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[22] National Grid and Ofgem have already been challenged by Scottish Power over methodologies for allocating transmission losses and for setting transmission prices in the electricity sector. Part of the basis for these challenges was the subjective decisions made by either party.

7. Further Consequences of Mod 116

Pulling together our description of the practicalities of the proposed modification and our analysis of the underlying economics, we can predict a number of specific consequences of Mod 116 for particularly parts of the gas sector and its consumers.

7.1. Investment in Generation

Under Mod 116, users would no longer be allowed to request interruptible tariffs and instead must book firm flat capacity if they wish to guarantee access in advance to the gas network on the majority of days, as they do at present.[23] Moreover, they will have to book flat and flexibility capacity to manage the variations in fuel use over their day.

Under exiting arrangements certain electricity generation plants can either book firm capacity or select interruptible tariffs and invest in alternative fuel sources in power stations. The choice between these options is made considering the relative cost of investing to accommodate alternative fuels or paying a share of NTS capacity costs. Those customers which are currently interruptible have found the NTS capacity costs outweigh the costs of investing in accommodating alternative fuels. In future, generators will have no clear basis upon which to make this assessment, since the total cost of interruptible capacity will be the cost of firm capacity less whatever National Grid is prepared to pay to buy-back firm capacity. National Grid's decisions about the volume and price of buy-back will inject a new and subjective source of risk for generators who are prepared to take interruptible capacity.

The requirement to buy flexibility capacity will also impose additional risk upon generators. Although many generators are the sole users of their exit point, they will have to participate in a market for flexibility capacity defined at "zonal", or "area" or even national level (depending on whether constraints bite). If flexibility capacity is ever tight, the price will vary unpredictably. However, given that flexibility capacity appears to be mostly in excess supply, the charge for it will be driven by the reserve prices set by National Grid. There is as yet no clear methodology for setting these prices, and it is not clear that there ever will be a stable, transparent and cost-reflective methodology.

The increase in risks and hence costs faced by investors would tend to deter investment in generation. Additionally, the investment signals regarding alternative fuel sources would shift, making investment in back-up fuel supplies less likely.

7.2. Investment in Storage

Storage operators generally opt for firm entry capacity and interruptible exit capacity, since they expect to deliver gas over entry capacity during peak periods but to withdraw gas over exit capacity (to replenish stocks) during off-peak periods. Under Mod 116, storage operators would be forced to book firm flat capacity for their exits. They might also need flexibility capacity, since the proposal would decide their need for capacity on the basis of the net flow, so variations in injections might be counted as variation in offtake, just because the facility was a net offtaker of gas over the day as a whole. Such a result would be perverse, if

[23] Interruptible customers can be interrupted up to 45 days per year at present.

the variation in injections was actually helping to balance the system. Overall, storage operators (or rather, their customers) would pay higher costs for use of the NTS than at present, thus lowering the value of storage capacity and discouraging investment in new storage facilities.

Moreover, Mod 116 would not provide any better signals for the construction of new storage facilities connected to the NTS, since the design of the flexibility product (1) provides no clear signal as to where more diurnal storage (or more gas swing) would reduce costs, and (2) because building diurnal storage would require users to buy more entry capacity, rather than enabling them to reduce their need for exit flexibility capacity. The scheme therefore charges users for using a service that is normally in excess supply, but does not allow users to reduce their demand for the service by investing in upstream alternatives.

Additionally, we understand from respondents to our questionnaire that the complexity of the new system (especially with regard to flexibility) would create a significant burden in allocating flows (and thus charges) to users and a greater complexity of contractual relationships with users. All of these factors would increase the overall costs of investment in storage facilities and thus potentially deter new investments. These problems apply more generally to all bi-directional points, including interconnectors.

7.3. Impact on Security of Supply

We can see no compelling evidence to suggest the likelihood of any overall improvement in security of supply, and on the contrary there may be some disadvantages.

Bi-directional points such as storage and interconnectors are vital to security of supply of gas in Great Britain. As discussed above, we can foresee a number of problems with the proposals that might discourage investment in these kinds of facilities by raising costs of operation and hence harm the security of supply in future.

Disincentives to invest in alternative fuel sources at generation facilities may also hinder security of electricity supply in certain circumstances.

Finally, given the possible difficulties in obtaining flexibility capacity at short notice, generators may be less willing to respond to the needs of the electricity market. Therefore, the introduction of Modification 116 or 116B might harm security of power supply in Great Britain. The inability of generators to obtain flexibility capacity at short notice might be mitigated by an effective Use-It-Or-Lose-It (UIOLI) scheme for flexibility, which would provide a stronger indication as to when flexibility capacity was available in greater quantities than the proposed 22 mcm. However, we understand that no UIOLI scheme for flexibility has been proposed as yet.

7.4. Impact on Competition

Discussions of the impact on competition (such as responses to our questionnaire) have tended to focus on the entry of shippers into the wholesale gas market. However, our analysis of the economics of pipelines indicates a more deep-seated effect on competition in the construction of pipelines and storage facilities.

7.4.1. Competition among shippers

The complexity of Modifications 116, 116B and 116C relative to the transitional arrangements (in particular the difficulties confronting network users at multi-shipper exit points and bi-directional flow points) creates a potential barrier to entry for shippers. Barriers to entry into the shipper business may arise in several ways:

§ The general complexity of rules design and transactions will increase the fixed costs and risks of entering the market as a shipper, thereby limiting the potential for small companies to enter the market.

§ The provision for awarding existing holders of exit capacity sufficient flat capacity to cover their “prevailing rights” has major advantages in terms of reducing risk to consumers. However, existing gas consumers will have to reach a satisfactory agreement with their shippers to permit the transfer of the capacity if they change their shipper. The negotiation and implementation of such arrangements will impose substantial administrative costs, which will act as a barrier to switching by gas consumers.

§ At exit points where there is no gas consumer to enforce the right to switch (i.e. interconnectors and storage facilities), such pre-emption of rights will act as a barrier to access. Although exemptions from Third Party Access offer the same sort of stability in access rights and are considered advantageous in many cases, the general application of the rule will cover some unnecessary obstacles to competition. (See below for a discussion of access to the Irish interconnector.)

§ Shippers at multiple offtake points may be unable to secure long term capacity commitments due to agency problems such as contracting and credit risk issues with the consumer and other shippers.

7.4.2. Competition among investments in transmission and storage

As mentioned several times above, the products created by Mod 116 lack an intrinsic or underlying logic in terms of pipeline assets and costs, since they do not indicate the geographical location of facilities and the associated constraints. This will prevent investors from competing efficiently with National Grid’s provision of transmission and storage services, including flexibility capacity or diurnal storage services.

For instance, if changes in the pattern or level of demand should ever result in a shortage of flexibility capacity, National Grid would currently use the exit capacity regime to ration what was available, but would not invest in additional flexibility alone. National Grid could change this policy by investing in additional flexibility. Users can invest in alternative diurnal storage (or reduce variations in their own consumption) at their own sites. Users can also invest in alternative pipelines to reduce their need for flat capacity. However, users *cannot* invest in upstream pipeline or storage capacity to provide more flexibility within the NTS.

National Grid therefore retains a monopoly over what might be the most economic method of dealing with a lack of linepack and diurnal storage. The entry-exit system is no better at providing such signals, but the proposed modifications extend and entrench National Grid’s monopoly power, by forcing users to acquire an additional service which they cannot provide themselves.

7.5. Trade Between EU Member States

The Moffat interconnector plays a vital role in supplying gas to Ireland, Northern Ireland and the Isle of Man. Currently, downstream Irish shippers book entry capacity at Moffat and nominate their gas deliveries on a daily basis to Bord Gáis Transportation (BGN). The Moffat agent then matches bookings upstream and downstream of Moffat and advises transporters and shippers of mismatches. Obtaining capacity downstream of Moffat allows the users to book firm NTS exit capacity at Moffat through their shipper. (Shippers which have not been appointed by downstream players in the Irish market may only book interruptible capacity at Moffat.)

Current NTS booking arrangements at Moffat would no longer work under Modifications 116C, 116 or 116B. A revision of the complex contractual arrangements at Moffat would, according to the Irish Commission for Energy Regulation (CER), "be a significant task and would involve multifaceted operational changes for those transacting at Moffat."[24] CER's observation is confirmed by the responses to our questionnaire which attempt to quantify the effects of the reforms on the Irish market.

Respondents active in the Irish gas sector expressed concern that the proposed system of prevailing rights might harm competition and compromise security of supply in the Irish gas market.

Under the proposed reforms, shippers downstream of Moffat could gain prevailing rights over NTS exit capacity upstream of Moffat. No gas consumer would be able to demand a contractual right to transfer this capacity to another shipper. As a result, the allocation of prevailing rights would create a barrier to entry into the Irish gas market (a barrier that was present within the British system and therefore under the jurisdiction of Ofgem).

Moreover, new users of the Moffat interconnector (i.e. new entrants to the downstream gas market) would need to reserve NTS exit capacity three years in advance, which would necessitate considerable forward planning on the part of new entrants and potentially unnecessary reinforcement of the NTS at the Moffat exit point. Therefore, new entrants will have to plan ahead to acquire capacity, but National Grid will have to recognise that additional exit capacity is not required at Moffat unless capacity on the interconnector is expanded.

Ofgem has not considered these costs, nor the implications for security of supply and competition in the Irish gas market. Ofgem's failure to consider these costs to Irish consumers results from Ofgem's statutory duty to consider the impact of its decisions on consumers in Great Britain. In our own cost benefit analysis of the effect of the proposed reforms (see chapter 9) we do not include costs incurred by Irish gas market players. However, we conclude that the UNC modification proposals do have an effect on trade between EU member states.

[24] *Implications for Ireland of Planned Reforms of UK Gas Transmission Exit Regime*, CER, 20/10/2006, p.7.

Article 3, paragraph 2 of European Commission regulation 1775/2005 states:

> *"Tariffs for network access shall not restrict market liquidity nor distort trade across borders of different transmission systems. Where differences in tariff structures or balancing mechanisms would hamper trade across transmission systems… transmission system operators shall, in close cooperation with the relevant national authorities, actively pursue convergence of tariff structures and charging"*.

It appears that the proposed reforms of NTS offtake arrangements will distort trade across the border between Great Britain and Ireland, affecting security of supply in the Irish gas market. The proposed exit capacity tariff structures also appear at odds with the requirement stated in regulation 1775/2005 that national regulatory authorities should strive for convergence in tariff structures and charging methodologies.

7.6. Summary and Conclusions

We have identified a number of undesirable impacts of Mod 116 and its alternatives and variants. Few of these impacts appear to have been discussed in detail and some run counter to the general claims made for the modifications. In particular, the lack of transparency in allocation and pricing of flexibility capacity conflicts with assertions that the system will improve long term incentives. The lack of a clear link between exit capacity and real network capacity undermines claims that future investment will be more efficient.

Additional costs and risks will make it more expensive to act as a shipper and therefore discourage entry. However, just as importantly, Mod 116 and Mod 116B introduce flexibility capacity, a service provided by facilities within and connected to the NTS, and which only National Grid can provide. Users may be able to reduce their need for this service at their exit points by investing within their own sites, but they will not be able to compete with flexibility capacity by investing in upstream facilities.

Finally, the effects on trade between EU member states are potentially serious and, in at least one case, are due to problems that fall within Ofgem's jurisdiction, namely the potentially permanent allocation of exit capacity to the Irish interconnector. Although we cannot comment on the legal implications of this factor, we believe it merits further consideration.

8. Potential for "Undue Discrimination"

During the consultation process regarding the divestment by National Grid of the four IDNs, Ofgem expressed concern that National Grid would "unduly discriminate" between DNs and DCs, and between IDNs and RDNs. Ofgem also suggested that allowing some customers to select interruptible tariffs is discriminatory to the detriment of firm customers, on which interruptible customers are free riding. Ofgem included the removal of potential discrimination among the non-quantifiable benefits listed in its IA. Our consideration of Mod 116 implies that this confidence in the proposed reforms is misplaced.

8.1. Discrimination Between Firm and Interruptible Users

Ofgem set out a definition of undue discrimination:[25]

> "*in circumstances where different shippers are paid or charged different prices, then the arrangements may not be unduly discriminatory if the prices are for different service levels and reflect the costs to users associated with providing those different service levels. Conversely, in circumstances where different shippers are paid uniform discounts or charged uniform prices, the arrangements may be unduly discriminatory if the shippers are providing or receiving different levels of services and the costs to shippers associated with providing those different service levels are not reflected in the price they pay or receive.*"

The current arrangements for interruptible loads do not result in undue discrimination by this definition, since shippers pay different prices for different service levels (i.e. firm vs. interruptible), and those differences in charges are related to the different costs of providing each service. That is, as long as interruptible customers are interrupted whenever demand from firm customers takes up all the available capacity, interruptible customers do not contribute to investment needs or increase the costs of capacity, so there is a reason for them to avoid capacity charges.

Certain interruptible customers on more heavily utilised parts of the system will be interrupted more frequently than those connected to other parts of the system. However, none of these users impose any costs and, provided that National Grid follows a fair procedure when deciding which customers to interrupt, there is no discrimination in this different level of service.

8.2. Discrimination between DNs and TCCs

Under the current NTS exit capacity arrangements, DNs must purchase a combination of NTS exit flat capacity and NTS offtake flexibility capacity to satisfy their gas offtake requirements. On the other hand, TCCs book a maximum daily quantity (MDQ) equal to 24 times their maximum hourly quantity (MHQ) and may obtain additional flexibility through

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25 See Ofgem (June 2004), *National Grid National Grid – Potential sale of gas distribution network businesses: Interruptions Arrangements – Regulatory Impact Assessment*, para 4.6 and 4.7.

the procedures laid down in the Network Code and other ancillary documents, like NExAS. Under Mod 116, both DNs and TCCs would be required to buy a combination of NTS exit flat capacity and NTS exit flexibility capacity to satisfy their gas offtake requirements. In Ofgem´s view, this should reduce the scope for undue discrimination between NTS offtake points.

8.2.1. Scope for discrimination within the proposed reforms

The proposed system of flat and flexibility capacity offers almost as many opportunities for discrimination between exit points as the previous internal arrangements, since the basis for setting charges lacks transparency (outlined in chapter 3) and allows National Grid to favour one group of customers or another. In addition, the opaque method used to determine and allocate physically available flexibility capacity leaves National Grid immense scope for use of its discretion and hence for discrimination between exit points.

Under Ofgem's proposed arrangements TCCs and DNs are expected to purchase flat and flexibility products by participating in auctions. In many of these auctions there will be a single bidder (i.e. the single shipper offtaking gas at a certain offtake point), so the clearing price will be the reserve price. In all these cases, then, there is the issue of how to calculate the reserve price of the flat and flexibility products in a transparent and non-discriminatory way, an issue that National Grid has not fully clarified so far.

As discussed in section 5.1.2 above, the link between peak capacity requirements and pipeline costs is well understood. The definition of capacity assigned to an exit point is open to debate, but National Grid has developed models for assigning routes to exit points and deriving cost-reflective prices from the costs of those assigned routes. In contrast, there is no obvious way to put a price on "flat capacity" (since it does not reflect peak demand or capacity requirements) or on "flexibility capacity" (which reflects a somewhat nebulous form of diurnal storage offered by National Grid's pipelines). In both cases, it will be impossible to see whether National Grid is engaging in discriminatory pricing - for instance, by pricing diurnal storage at the cost of storage available to the user, rather than at the cost of providing the service – because there will be no objective measure of the costs involved.

8.2.2. Alternative ways to reduce discrimination

We suggested in our previous report that a better way to avoid undue discrimination would be to extend to DNs the transitional arrangements which apply to TCCs, by making DNs book a MDQ that reflects 24 times their MHQ as set out in the procedures laid down in the Network Code. We cannot say whether this approach would present National Grid with an operational problem, since the calculation of available flexibility capacity seems to indicate that there is a surplus available. Moreover, the definition of the two products seems to indicate that a major concern of National Grid is the rate of deliverability during the 16-hour peak period, a definition of capacity which appears not to have been considered. Since National Grid is the only party able to choose whether to provide that level of deliverability by expanding pipelines or using diurnal storage within the NTS, it might be sufficient to show users the cost of providing peak time deliverability (100 mcm/hour in Figure 5.4) and to let National Grid decide on the best way to provide it.

As noted above, an even better way to provide investment signals to users would involve breaking down exit capacity into its different segments by area and zone (as National Grid is happy to do for flexibility capacity) and to link it to entry capacity so that users can compete with National Grid's provision of diurnal storage using their own facilities and gas swing. Again, we are unaware of any discussion of this possible solution.

Extending the transitional arrangements to DNs would allow them to contract for their flexibility needs within an established, transparent and non-discriminatory framework. It also avoids the need for TCCs to contract for flexibility products through National Grid, which greatly increases shippers' transaction costs and costs to consumers, as we show in chapter 9.

8.3. Discrimination Between IDNs and RDNs

Ofgem has expressed the concern that National Grid may have incentives to favour its own regional distribution networks (RDNs) at the expense of independent distribution networks (IDNs), for example, by making IDNs spend more than RDNs in capex.

The transitional arrangements already address this issue by introducing a common contractual relationship between all DNs and National Grid, so that the scope for undue discrimination in capacity allocation is greatly reduced. However, as discussed above, the rules applying to DNs under the transitional arrangements (and applying to TCCs under Mod 116) create immense scope for National Grid to discriminate in pricing its services, because they are hard to relate to the costs of real facilities. Thus, the pricing arrangements that Ofgem has applied to DNs and is proposing to extend to TCCs through Mod 116 create the potential for undue discrimination, compared with a system that required all users to book capacity defined by its MHQ, as is conventional in many other systems.

In addition, the transitional arrangements (and Mod 116) give National Grid immense discretion over buy-back arrangements, so there is a danger that it would prefer to buy capacity back from holders at RDN exit points rather than at IDNs (or from TCCs). Therefore, neither the transitional arrangements applied to DNs, nor the application of Mod 116 to TCCs, removes the scope for discrimination between RDNs and IDNs (or TCCs, for that matter).

8.4. Summary and Conclusions on Discrimination

Mod 116 introduces two new aspects to exit capacity charging: longer term commitments and a new flexibility capacity product. The aim is to enhance signals for efficiency, but Mod 116 is unlikely to achieve this aim.

First, the extension of capacity booking will not provide accurate signals about demands for investment in capacity, since the capacity booking timetable will still not require users to commit for the whole life of the assets or the pay the full cost of investments. Decisions will still rely on the judgement of National Grid operating within a set of regulatory incentives. Information will be imperfect for Ofgem as well as for National Grid, and so will not help to improve regulatory incentives or the efficiency of National Grid's investment decisions.

Another problem lies in the definition of the capacity services, which National Grid will not be able to relate to costs in a transparent manner. The economics of gas pipelines are relatively straightforward, but remain hidden within an entry-exit system by (1) the separation of entry capacity from exit capacity and (2) the amalgamation of capacity over different routes into a single leg of exit capacity. Within an entry-exit system, it is therefore impossible to give users and competitors to National Grid accurate signals about where investment is required to augment capacity or to overcome technical problems.

Mod 116 may be an attempt to address some problems facing National Grid, but it does not overcome this basic flaw in the entry-exit system. Instead it only succeeds in creating additional complexity in a non-transparent way, and can at best provide a little additional information to National Grid.

9. Revised Cost-Benefit Analysis

Building on the preceding chapters' discussion of the economics of pipeline capacity, the economics undue discrimination and the incentive effects of Mod 116 and drawing on our appraisal of Ofgem's IA in Appendix A, we have conducted a cost-benefit analysis of the four modification proposals. Our analysis is, in part, based on the responses to a questionnaire which NERA circulated to industry players and other interested parties.

This chapter first describes the questionnaire which NERA circulated to industry players and interested parties, asking for estimates of the costs and benefits which respondents would incur as a result of the proposed reforms. Based on the responses to our questionnaire, we then outline the method used to obtain estimates of costs incurred by all affected parties. We present the cost estimates that we obtained.

Following the derivation of estimated costs of the proposed reforms, we draw on the conclusions of the previous chapter to quantify the benefits of the four modification proposals.

Finally, we compare the costs and benefits estimated and draw conclusions on the merits of the reform proposals.

9.1. NERA's Questionnaire

In order to quantify the costs and benefits which Modification 116 and its alternatives would impose on the industry, we circulated a questionnaire to various industry players, asking them to quantify the costs and benefits to their businesses of the proposed reforms. We asked for quantified and descriptive information on:

- the benefits of the proposed reforms;
- the one-off and ongoing IT costs of the reforms;
- the one-off and ongoing operational/commercial staffing costs of the reforms;
- the one-off and ongoing regulatory/legal staffing costs of the reforms;
- the one-off and ongoing credit costs of the reforms;
- the one-off and ongoing costs of the reforms due to changes in risk; and
- any other costs of the proposed reforms.

The questionnaire asked respondents to estimate separately the costs and benefits resulting from the reforms envisaged by Modification 116 and the three alternatives. We received responses from 8 shippers, 3 players in the Irish gas market, 1 GDN, 2 industrial TCCs, 2 storage operators and 1 future storage operator. We show a copy of the questionnaire in Appendix B.[26] We list respondents to our questionnaire in Appendix C.

[26] With the questionnaire, we circulated a spreadsheet form into which respondents were asked to write answers. The spreadsheet detailed the breakdown of costs described in this section.

9.2. Analysis of Costs

We used the responses to NERA's questionnaire to estimate the total costs of reforming NTS offtake arrangements. The estimation of the total costs to all affected parties is equivalent to estimating the costs which are likely to be passed onto consumers at some stage in the future.

In the following subsections, we describe the methods used to estimate the costs of reforms based on the data obtained through our questionnaire. As we did not receive questionnaire responses from all industry players, we describe the method used to extrapolate whole industry costs for each type of industry player.

In all our analyses, we excluded additional costs which respondents expect to pay as a result of becoming liable for an increased share of total NTS offtake charges. We only considered one-off and ongoing costs which were not payments for exit capacity. In all our PV calculations we use a 6% discount rate and discount over 20 years, which corresponds to the approach used by Ofgem in their *Draft Enduring Offtake Impact Assessment*.[27]

The results of our cost analysis are presented in an incremental format. That is, we show the incremental cost of introducing:

§ Modification 116A compared to maintaining the transitional arrangements;

§ Modification 116C compared to implementing Modification 116A;

§ Modification 116 compared to implementing Modification 116C; and

§ the incremental benefit from introducing Modification 116B rather than Modification 116.

We also report the total cost of implementing Modification 116.

9.2.1. Shippers' Costs

To estimate costs to all shippers arising from each of the proposed reforms, we find the PV of costs which respondents expect to incur and extrapolate the PV of costs for non-respondents using three approaches:

§ Method 1: we extrapolate the total costs to all shippers by dividing the summed PVs of respondents' costs by the fraction of all TCC exit capacity which the respondents hold. That is, we gross up costs on the basis of TCC exit capacity held.28

§ Method 2: We assume that (1) some costs to shippers of each reform are fixed, and thus invariant to the volume of TCC exit capacity held and (2) that the fixed costs for all shippers are equal to the lowest total cost reported by the respondents. That is, we multiply the lowest total cost reported by the respondents by the total number of TCC

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[27] *Draft Enduring Offtake Impact Assessment*, Transmission Price Control Review: Initial Proposals, Ofgem 104d/06, 26/06/2006.

[28] Where our cost analyses make use of data on the total amount of exit capacity held at any subset of NTS exit points, we use data from appendix seven of *Ofgem's Transmission Price Control Review: Updated Proposals* (September 2006) document. This document also provides data on the number of offtake points by type of connection.

shippers29 and then gross up variable costs of all shippers by dividing the implied total variable costs of respondents by the fraction of all TCC exit capacity which the respondents hold. That is, we gross up variable costs on the basis of TCC exit capacity held.30

- Method 3: we extrapolate the total costs to all shippers by dividing the summed PVs of respondents' costs by the fraction of all NTS exit capacity (i.e. DC and DN exit capacity) which the respondents hold. That is, we gross up costs on the basis of total exit capacity held at all exit points.

Because the proposed reforms have most effect on TCC exit capacity, we consider that the most appropriate method for extrapolating costs to all shippers is method 1, which grosses up on the basis of TCC exit capacity held.

To examine the results of our analysis graphically, for each responding shipper we calculated the average cost of the modification proposals per GWh/day of TCC exit capacity held and plotted the results (shown in Figure 9.1). The figure demonstrates that the costs of each reform proposal for all but one of the responding shippers are in similar orders of magnitude. One shipper's costs differed from the others by several orders of magnitude, however. (The three data points relating to the high cost shipper are circled in the figure.) Given the scale of the difference, we decided that the shipper with these relatively high costs was an outlier meriting special attention.

Table 9.1 therefore presents our estimated costs of the reforms to shippers for two cases: (1) where the outlier is included and (2) where it is excluded.[31] Given the degree to which the cost estimates of the outlier differ from other shippers' estimates, the cost estimates which omit the outlier's estimates may be more accurate. However, the inclusion of the outlier makes little overall difference to the magnitude of aggregated costs to all shippers.

Table 9.1 also shows the costs caused by each of the modifications in order of increasing complexity (and hence cost). For each of the three methods of extrapolation, the shaded row indicates the total cost of the basic proposal, Mod 116. The final row for each method shows the incremental benefit of Mod 116B over Mod 116.

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[29] In line with Ofgem's IA, we assume there are 16 shippers in total serving TCCs.

[30] Note that this approach yields identical results to method 1 in some cases. For certain reform proposals, at least one shipper indicated that there were no costs associated with its introduction, leading to an estimated fixed cost of zero.

[31] In contrast to Ofgem's "cluster analysis," we have not completely omitted any observations and we have not given special treatment to observations of costs with similar orders of magnitude to other observations.

Figure 9.1
Shippers' Average Costs of Modification Proposals

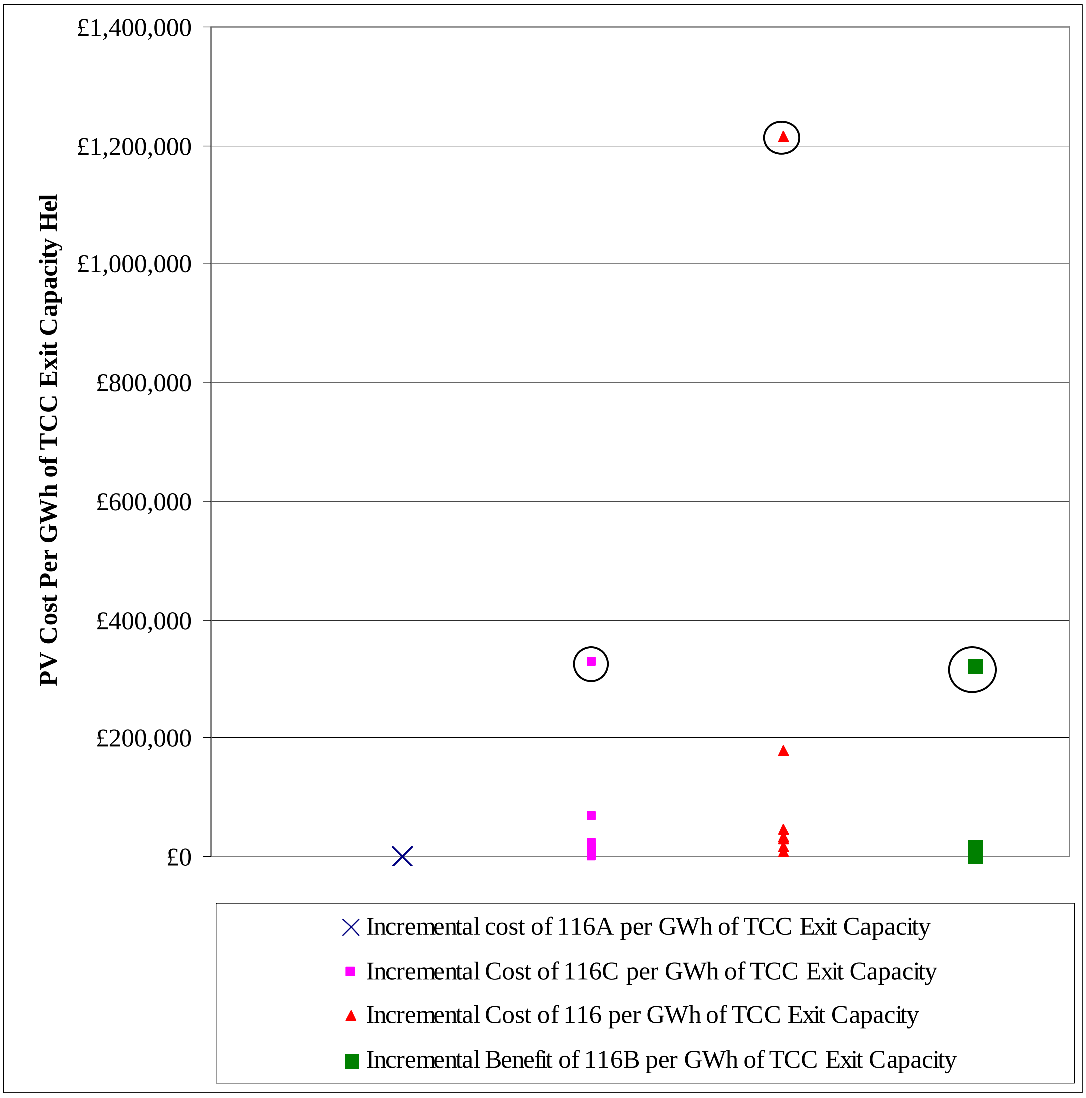

Table 9.1
Shipper Costs

Shipper Costs		With Outlier			Without Outlier		
		One-off Costs	Ongoing Costs	NPV of Total Costs	One-off Costs	Ongoing Costs	NPV of Total Costs
Method 1	Incremental Cost of Mod 116A Compared to Transitional Arrangements	£0.02 m	£0 m	£0.02 m	£0.02 m	£0 m	£0.02 m
	Incremental Cost of Mod 116C Compared to Mod 116A	£1.98 m	£1.32 m	£15.53 m	£1.71 m	£1.21 m	£14.19 m
	Incremental Cost of Mod 116 Compared to Mod 116C	£5.00 m	£2.66 m	£32.37 m	£4.65 m	£2.34 m	£28.72 m
	Total Cost of Implementing Mod 116 Compared to Transitional Arrangements	£7.00 m	£3.97 m	£47.92 m	£6.38 m	£3.55 m	£42.93 m
	Incremental Benefit of Mod 116B Compared to Mod 116	£0.32 m	£0.66 m	£7.12 m	£0.26 m	£0.54 m	£5.78 m
Method 2	Incremental Cost of Mod 116A Compared to Transitional Arrangements	£0.02 m	£0.00 m	£0.02 m	£0.02 m	£0.00 m	£0.02 m
	Incremental Cost of Mod 116C Compared to Mod 116A	£1.98 m	£1.32 m	£17.98 m	£1.71 m	£1.21 m	£16.45 m
	Incremental Cost of Mod 116 Compared to Mod 116C	£5.55 m	£2.99 m	£41.89 m	£5.36 m	£2.76 m	£38.94 m
	Total Cost of Implementing Mod 116 Compared to Transitional Arrangements	£7.55 m	£4.30 m	£59.88 m	£7.09 m	£3.97 m	£55.41 m
	Incremental Benefit of Mod 116B Compared to Mod 116	£0.32 m	£0.66 m	£8.35 m	£0.26 m	£0.54 m	£6.78 m
Method 3	Incremental Cost of Mod 116A Compared to Transitional Arrangements	£0.02 m	£0.00 m	£0.02 m	£0.02 m	£0.00 m	£0.02 m
	Incremental Cost of Mod 116C Compared to Mod 116A	£2.45 m	£1.62 m	£19.17 m	£2.12 m	£1.50 m	£17.61 m
	Incremental Cost of Mod 116 Compared to Mod 116C	£6.17 m	£3.28 m	£39.96 m	£5.77 m	£2.90 m	£35.64 m
	Total Cost of Implementing Mod 116 Compared to Transitional Arrangements	£8.64 m	£4.91 m	£59.15 m	£7.91 m	£4.41 m	£53.26 m
	Incremental Benefit of Mod 116B Compared to Mod 117	£0.39 m	£0.82 m	£8.79 m	£0.32 m	£0.67 m	£7.17 m

9.2.2. Storage Operator Costs

We note from examination of the questionnaire results, that the costs reported by responding storage operators seem to relate to working gas volume at the respondents' respective facilities. We therefore first calculated the costs of the whole storage operator sector by adjusting for the difference in the volume of *working gas*.

A number of gas storage facilities are expected to open in the coming years in the UK. Our results differ according to whether we extrapolated cost to the total size of the existing storage industry or to its expected size in the future, so we adopted both methods. When considering the costs to likely new entrants to the UK market for storage capacity, we assume that they do not face the one-off costs of implementing Modification 116 and the variants thereof. We do so because they would not have to replace existing IT systems and change procedures to accommodate the proposed reforms as they would require that new systems be put in place anyway. Thus, the cost of the reforms to new entrants is lower. However, we assume that new entrants will be subject to the ongoing increased cost of operation resulting from the reforms.

The storage operators which responded to our questionnaire estimated costs based on the assumption that they would act as the agent which allocates flexibility overrun charges under Modification 116 and Modification 116B, which both introduce the flexibility exit capacity product. We discuss the difficulties faced by storage operators which result from Modification 116 and its variants in section 4.3.

As well as extrapolating costs for all storage operators from the proposed reforms based on working gas capacity, we also extrapolated costs for all existing storage operators based on *NTS exit capacity* held at relevant exit points. It would be desirable to include the (limited) additional costs imposed on new storage operators, but we had no data on exit capacity used by future storage facilities.

The estimated costs to storage operators are shown in Table 9.2, which follows the same structure as Table 9.1. As before, the shaded rows show the total costs of Mod 116, as the sum of the incremental costs of the individual reforms. The estimated costs to storage operators range from £0 to £5 million, depending upon the Modification and basis for extrapolating total industry costs. Most costs resulting from the proposed reforms are associated with the difference between Mod 116 and Mod 116C, i.e. with the effect of introducing flexibility capacity.

Table 9.2
Storage Operator Costs

Storage Operator Costs			One-off Costs	Ongoing Costs	NPV of Total Costs
Existing Storage Facilities	**Extrapolate on Basis of NTS Exit Capacity Held at Responding Facilities**	Incremental Cost of Mod 116A Compared to Transitional Arrangements	£0.00 m	£0.00 m	£0.00 m
		Incremental Cost of Mod 116C Compared to Mod 116A	£0.10 m	£0.07 m	£0.96 m
		Incremental Cost of Mod 116 Compared to Mod 116C	£2.53 m	£0.09 m	£3.60 m
		Total Cost of Implementing Mod 116 Compared to Transitional Arrangements	£2.64 m	£0.16 m	£4.56 m
		Incremental Benefit of Mod 116B Compared to Mod 116	£0.00 m	£0.00 m	£0.00 m
	Extrapolate on Basis of Working Gas Capacity	Incremental Cost of Mod 116A Compared to Transitional Arrangements	£0.00 m	£0.00 m	£0.00 m
		Incremental Cost of Mod 116C Compared to Mod 116A	£0.07 m	£0.05 m	£0.70 m
		Incremental Cost of Mod 116 Compared to Mod 116C	£1.84 m	£0.06 m	£2.62 m
		Total Cost of Implementing Mod 116 Compared to Transitional Arrangements	£1.91 m	£0.12 m	£3.31 m
		Incremental Benefit of Mod 116B Compared to Mod 116	£0.00 m	£0.00 m	£0.00 m
Current and Future Storage Facilities *	**Extrapolate on Basis of Working Gas Facility**	Incremental Cost of Mod 116A Compared to Transitional Arrangements	£0.00 m	£0.00 m	£0.00 m
		Incremental Cost of Mod 116C Compared to Mod 116A	£0.07 m	£0.09 m	£1.11 m
		Incremental Cost of Mod 116 Compared to Mod 116C	£1.94 m	£0.19 m	£3.90 m
		Total Cost of Implementing Mod 116 Compared to Transitional Arrangements	£2.01 m	£0.28 m	£5.02 m
		Incremental Benefit of Mod 116B Compared to Mod 116	£0.00 m	£0.00 m	£0.00 m

* Ongoing costs for new storage facilities enter the NPV calculation in the year when it is expected that they will commence opertion.

9.2.3. TCC Costs

Shippers would – to some extent – pass through to TCCs the costs they incur as a result of any implemented reforms. TCCs would also incur costs in addition to the costs passed through to them from shippers. From the responses to our questionnaire from 2 industrial TCCs and from discussions with an industry body representing 11 industrial TCCs, we understand that one-off costs would arise from the consultancy necessary for large gas users to understand the reforms and plan their businesses in light of a new charging structure for NTS exit capacity.

During discussions with the industry body representing these 11 industrial TCCs, it was suggested that most ongoing costs resulting from the proposed reforms would arise

§ from the introduction of a flexibility capacity product and the need to monitor usage of flexibility;

§ from the removal of long-term interruptible capacity booking rights;

§ from the requirement to book capacity several years in advance of gas day; and

§ from increased complications in the contractual relationship between TCCs and their shippers.

We understand from our discussions that the costs indicated by the TCC respondents are broadly representative of those that other TCCs would incur.

To calculate our estimate of costs to TCCs, we have multiplied the average one-off and ongoing costs of the TCC respondents by the number of TCC sites on the NTS (excluding storage sites and interconnectors).

Because the cost estimates provided by the respondents relate to the costs of implementing Modification 116, we have estimated costs for the other reform proposals as follows. For Modification 116A, we assume there are no one-off or ongoing costs, as this modification essentially preserves the current system.

Under Modification 116C, we assume that the estimated one-off costs are incurred, as the one-off costs principally arise from the necessary consultancy advice for TCCs to understand the new system. Under Modification 116C we assume that ongoing costs to TCCs are zero, which accounts for the fact that the flexibility product is not introduced. Exclusion of ongoing costs from estimated TCC costs under Modification 116C may under account for costs as long-term interruptible capacity booking is prevented (as under Modification 116). For Modification 116B we assume that the costs are the same as for Modification 116.

The results of this analysis are shown in Table 9.3. The shaded row shows that the total cost to TCCs of implementing Modification 116 is £33.69 million in present value terms. Almost all of this cost is associated with the difference between Mod 116 and Mod 116C, i.e. with the introduction of flexibility capacity.

Table 9.3
TCC Costs

TCC Costs	One-off Costs/Benefit	Ongoing Costs/Benefits	NPV of Total Costs/Benefits
Incremental Cost of Mod 116A Compared to Transitional Arrangements	£0.00 m	£0.00 m	£0.00 m
Incremental Cost of Mod 116C Compared to Mod 116A	£2.07 m	£0.00 m	£2.07 m
Incremental Cost of Mod 116 Compared to Mod 116C	£0.00 m	£2.24 m	£31.62 m
Total Cost of Implementing Mod 116 Compared to Transitional Arrangements	£2.07 m	£2.24 m	£33.69 m
Incremental Benefit of Mod 116B Compared to Mod 116	£0.00 m	£0.00 m	£0.00 m

9.2.4. Transporters' Costs

The response to our questionnaire from a GDN provided some estimates of the costs incurred through the introduction of Modification 116. However, the responding network operator advised us that its cost estimates were too inaccurately estimated for use in our cost benefit analysis due to uncertainty over the implications of the proposed reforms for GDNs.

Because we received a response from only one GDN, we are unable to report aggregated cost information for reasons of confidentiality. However, we were able to estimate total GDN costs from cost estimates received by the responding GDN by grossing up this GDN's cost estimates by the proportion of all NTS exit capacity to GDNs.[32]

In its IA, Ofgem estimated that the costs to transporters associated with the introduction of the enduring arrangements, as envisaged by Modification 116, would lie between £24.5 million and £20 million. Our cost estimate of costs to GDNs, calculated from the cost estimation of the responding GDN, is over three times that estimated by Ofgem.[33] However, because we cannot report the costs estimated by the responding GDN, because it does not affect the final conclusion of this cost benefit analysis, and because of the uncertainty over

32 We also grossed up by the total number of DNs and found similar results.

33 For reasons of confidentiality, we cannot report the exact figures given by the respondent to our questionnaire in this case.

the responding GDN's cost estimate, we assume that costs to transporters of Modification 116 lie between £24.5 million and £20 million. However, we recognise that costs of GDNs may be significantly higher.

Of the assumed costs to transporters of between £24.5 million and £20 million, we assume that 25% of these are incurred under Modification 116A, a further 50% of these are incurred under Modification 116C and the remaining 25% are incurred under Modifications 116 or 116B.

The large disparity between NERA and Ofgem's estimates of transporter costs may be related to Ofgem's "cluster analysis," in which it eliminated the highest cost estimate of "NPV cost per offtake point" in its sample of four transporters. In such a small sample, we consider it inappropriate to remove an observation in this manner, as we discuss in our comment on Ofgem's evaluation of the NERA/TPA report.

In Ofgem's IA, which was conducted prior to the sale of the four IDNs, Ofgem did not include the costs incurred by transporters in its final cost benefit analysis. The costs faced by DNs will eventually be passed through to customers, if not through increased capacity charges then through the rate of return which investors will demand. We therefore conclude that transporter costs should be included in the cost benefit analysis, but present total costs with and without DN costs for ease of comparison with the Ofgem IA.

Note that we have no information on the costs to National Grid of implementing the modification proposals.

9.2.5. Costs to Irish Respondents

We received questionnaire responses from three players in the Irish gas market. Ofgem does not consider the effects of the proposed UNC modifications on the Irish gas market in its IA. Therefore, for comparability between our cost-benefit analysis and that conducted by Ofgem, we omit the costs to Irish players from our analysis. However, to indicate the scale of effect on the Irish gas market caused by the introduction of Mod 116 and its alternatives and variants, we report the aggregated and discounted costs of the Irish respondents to our questionnaire in Table 9.4.

The table shows that the aggregated and discounted costs that the three Irish respondents would incur from the introduction of Mod 116 is £6.21 million. We expect that total costs incurred by all players in the Irish gas market resulting from the proposed reforms to be higher than this figure.

Table 9.4
Costs to Irish Gas Market Respondents

	PV of Costs to Irish Respondents
Incremental Cost of Mod 116A Compared to Transitional Arrangements	£0 m
Incremental Cost of Mod 116C Compared to Mod 116A	£1.77 m
Incremental Cost of Mod 116 Compared to Mod 116C	£4.44 m
Total Cost of Implementing Mod 116 Compared to Transitional Arrangements	£6.21 m
Incremental Benefit of Mod 116B Compared to Mod 116	£0 m

9.2.6. Summary of Cost Analyses

We present the full set of results from our cost analyses in Table 9.5. The central case gives our estimate of the costs which are likely to occur as a result of each respective modification proposal based on the methodologies which we consider most appropriate. That is, in the central case

- we extrapolate costs to all shippers by grossing up based on TCC exit capacity held (method 1); and
- we extrapolate costs to storage operators using working gas capacity and consider the costs of reforms to new entrants to the market for storage capacity as well as incumbents.

The shaded column shows the total cost of Mod 116. If we exclude the outlier from the analysis of shipper costs and overlook costs to transporters, we find a total cost of implementing Mod 116 in our central case of £81.6 million, which one should compare to Ofgem's estimate of total costs of £35.1 million in its high cost case. Thus, we obtain much higher cost estimates than Ofgem's IA.

Table 9.5
Total Costs

Figures in NPV Using 6% discount Rate and Discounting Over 20 Years	Incremental Cost of Mod 116A Compared to Transitional Arrangements	Incremental Cost of Mod 116C Compared to Mod 116A	Incremental Cost of Mod 116 Compared to Mod 116C	Total Cost of Implementing Mod 116 Compared to Transitional Arrangements	Incremental Benefit of Mod 116B Compared to Mod 116
Storage Operators					
Extrapolate using working gas capacity					
Current operators	£0 m	£0.7 m	£2.6 m	£3.3 m	£0.0 m
Including future operators	£0 m	£1.1 m	£3.9 m	£5.0 m	£0.0 m
Extrapolate using exit capacity					
Current operators	£0 m	£1.0 m	£3.6 m	£4.6 m	£0.0 m
Shipper Costs					
Including the outlier					
Method 1	£0.0 m	£15.5 m	£32.4 m	£47.9 m	£7.1 m
Method 2	£0.0 m	£18.0 m	£41.9 m	£59.9 m	£8.4 m
Method 3	£0.0 m	£19.2 m	£40.0 m	£59.2 m	£8.8 m
Excluding the outlier					
Method 1	£0.0 m	£14.2 m	£28.7 m	£42.9 m	£5.8 m
Method 2	£0.0 m	£16.4 m	£38.9 m	£55.4 m	£6.8 m
Method 3	£0.0 m	£17.6 m	£35.6 m	£53.3 m	£7.2 m
TCC Costs	£0.0 m	£2.1 m	£31.6 m	£33.7 m	£0.0 m
TOTAL (excl. Transporter Costs)					
Including the outlier					
Low	£0.0 m	£18.3 m	£66.6 m	£84.9 m	£7.1 m
Central	£0.0 m	£18.7 m	£67.9 m	£86.6 m	£7.1 m
High	£0.0 m	£22.4 m	£77.4 m	£99.8 m	£8.8 m
Excluding the outlier					
Low	£0.0 m	£17.0 m	£63.0 m	£79.9 m	£5.8 m
Central	£0.0 m	£17.4 m	£64.2 m	£81.6 m	£5.8 m
High	£0.0 m	£20.8 m	£74.5 m	£95.3 m	£7.2 m
Transporter Costs					
Ofgem High	£6.1 m	£12.3 m	£6.1 m	£24.5 m	£0.0 m
Ofgem Low	£5.0 m	£10.0 m	£5.0 m	£20.0 m	£0.0 m
TOTAL (incl. Transporter Costs)					
Including the outlier					
Low	£5.0 m	£28.3 m	£71.6 m	£104.9 m	£7.1 m
Central	£5.0 m	£28.7 m	£72.9 m	£106.6 m	£7.1 m
High	£6.1 m	£34.6 m	£83.5 m	£124.3 m	£8.8 m
Excluding the outlier					
Low	£5.0 m	£27.0 m	£68.0 m	£99.9 m	£5.8 m
Central	£5.0 m	£27.4 m	£69.2 m	£101.6 m	£5.8 m
High	£6.1 m	£33.0 m	£80.6 m	£119.8 m	£7.2 m
Ofgem RIA Estimates of Total Costs					
Low				£33.2 m	
Central				£33.5 m	
High				**£35.1 m**	

9.3. Analysis of Benefits

Appendix A contains a description and evaluation of the benefits that Ofgem attributes to the enduring arrangements. In light of chapters 5 to 8, and drawing on the conclusions of Appendix A, this section will outline the benefits which we expect will result from the four modification proposals. We compare the benefits we identify to those identified by Ofgem in its IA.

9.3.1. Imputed benefits of removing regulatory uncertainty

Whatever the outcome of the consultation process on the reform of NTS offtake arrangements, as long as a permanent solution is reached, some imputed benefits will arise from the removal of regulatory uncertainty which is created by the sunset clauses in the UNC.

Given that Mod 116A extends the transitional arrangements, and thereby removes risk with the lowest possible costs of implementation, we assume that the benefits of removing regulatory uncertainty are at least equal to the costs of implementing Mod 116A. We also assume that the benefits from the removal of regulatory uncertainty apply to all four modification proposals in equal measure. We therefore impute to each modification proposal a benefit equal to the costs of implementing Mod 116A, with the result that the net benefit of Mod 116A is zero. It would be higher if the benefit of reducing regulatory risk were higher, but higher figures would not affect the ranking of each modification.

9.3.2. Benefits from capex efficiencies

In its IA, Ofgem anticipates capex efficiency benefits from introducing the enduring arrangements (envisaged by Modification 116) as a result of the introduction of longer-term contacting for capacity. Capex efficiency benefits do not arise from the separation of flat and flexible exit capacity. That is, there are no capex efficiency benefits of charging separately for flat and flexible exit capacity through enhanced investment signals, as investment is driven by “end of day” requirements, and National Grid will not invest solely to increase flexibility capacity. We discuss the benefits arising from capex efficiencies in section A.3 of Appendix A.

Therefore, in our cost benefit analyses of the four modification proposals, we attribute capex efficiency benefits of the reforms which we identify equally to Modification 116C, Modification 116 and Modification 116B, with none of the capex efficiency benefits attributed to Modification 116A. However, we note that many of these benefits could be applied to Modification 116A too, were Ofgem to reconsider its policy of limiting the length of ARCAs.

We present our estimates of the likely PV of benefits of the reforms from capex efficiencies in Table 9.6 and Table 9.7.

Table 9.6
Benefits of Modification 116 Through Capex Efficiencies

PV of Benefits 2005/06 Prices	Ofgem IA	NERA Analysis
High Case	£44.9 m	£12 m
Central Case	£37.6 m	£6 m (mid-point)
Low Case	£30.3 m	£0

Table 9.7
NERA Analysis of Capex Efficiency Benefits from Proposed UNC Modification

2005/06 Prices	PV of Benefits (NERA Analysis)
Incremental Benefit of Implementing Modification 116A Compared to the Transitional Arrangements	£0
Incremental Benefit of Implementing Modification 116C Compared to Implementing Modification 116A	£0 - £12 m
Incremental Benefit of Implementing Modification 116 Compared to Implementing Modification 116C	£0
Total Benefit of Implementing Modification 116 Compared to the Transitional Arrangements	£0 - £12 m
Incremental Benefit of Modification 116B Compared to Modification 116	£0

9.3.3. Benefits from reduced discrimination

Ofgem identified between £16.8 million and £25.2 million of benefits from the non-discriminatory allocation of capacity products which Ofgem envisages under the enduring arrangements. We do not expect there to be benefits from the proposed reforms in terms of reducing the likelihood of National Grid "unduly discriminating" between NTS users. Discrimination between users is just as likely under the enduring arrangements (envisaged by Mod 116) as under the transitional arrangements. The scope for discriminatory behaviour under Mod 116 arises mainly through the lack of transparency and the considerable discretion available to National Grid in buy-back arrangements, charging methodologies, capacity release and investment decisions. We discuss the benefits arising from reduced discrimination in section A.4 of Appendix A.

We did not therefore include any benefits in our analysis attributable to reductions in the potential for undue discrimination under any of the modification proposals.

9.3.4. Benefits from reduced incidence of ARCAs

Although benefits would arise as a result of the reforms from reduced incidence of ARCAs, Ofgem has not considered the possibility that the system envisaged under the proposed UNC modifications would generate different types of dispute, regarding NExAs, for example. Additionally, the complexity of the new regime would increase the cost of scrutinising National Grid's decisions over the allocation and pricing of exit capacity products.

The additional complexity of the enduring arrangements will affect the incidence and cost of disputes. We therefore conclude in section A.5 of Appendix A that the benefits Ofgem expects to arise through reduced incidence of ARCAs from the introduction of Modification 116 are unrealistically high. We attribute the benefits due to reduced incidence of disputes to Modifications 116, 116C and 116B in Table 9.8.

Table 9.8
NERA Analysis of Benefits from Reduced Incidence of ARCAs

2005/06 Prices	**PV of Benefits (NERA Analysis)**
Incremental Benefit of Implementing Modification 116A Compared to the Transitional Arrangements	£0
Incremental Benefit of Implementing Modification 116C Compared to Implementing Modification 116A	£0 - £5 m
Incremental Benefit of Implementing Modification 116 Compared to Implementing Modification 116C	£0
Total Benefit of Implementing Modification 116 Compared to the Transitional Arrangements	£0 - £5 m
Incremental Benefit of Modification 116B Compared to Modification 116	£0

Table 9.9 compares our estimate of these benefits to the benefits estimated by Ofgem.

Table 9.9
Comparison of NERA and Ofgem Benefits from Reduced Incidence of ARCAs

	Benefits of Modification 116
Ofgem Low Case	£7.5 m
Ofgem Base Case	£10 m
Ofgem High Case	£14.8 m
NERA Estimate	£0 - 5 m

9.3.5. Summary of benefits

Table 9.10 summarises the benefits which we expect would arise from the various UNC modification proposals and would eventually be passed through to consumers. Table 9.10 shows that we envisage a maximum of £17 million of total benefits from the introduction of Modification 116.

Table 9.10
Summary of Benefits Envisaged by NERA Analysis

2005/06 Prices	**PV of Benefits (NERA Analysis)**
Incremental Benefit of Implementing Modification 116A Compared to the Transitional Arrangements	£5 - £6.1 m
Incremental Benefit of Implementing Modification 116C Compared to Implementing Modification 116A	£0 - £17 m
Incremental Benefit of Implementing Modification 116 Compared to Implementing Modification 116C	£0
Total Benefit of Implementing Modification 116 Compared to the Transitional Arrangements	£5 - £23.1 m
Incremental Benefit of Modification 116B Compared to Modification 116	£0

9.4. Comparison of Costs and Benefits

Table 9.11 shows a detailed comparison of costs and benefits based on the estimates from this chapter. All the calculations in Table 9.11 exclude the shipper outlier and include the costs to transporters. The table reports the NPV of net benefits of each reform proposal (i.e. the PV of benefits less the PV of costs of each proposal in NPV terms). Table 9.11 is summarised by Table 9.12. As before, both tables report the incremental net benefit of each proposed reform and the total net benefit of Mod 116.

Table 9.11 shows that the NPVs of all modification proposals are negative. In particular, we note that the net benefit in NPV terms of introducing Modification 116 varies between -£78 million and -£114 million. It is clear from the results of our analysis that the costs of Modifications 116, 116B and 116C significantly outweigh the benefits gained through their introduction. The net benefit of introducing modification 116A is fixed at zero by the method used to calculate the benefit from the removal of regulatory uncertainty.

Modification 116C generates a negative net benefit, but its introduction would be far less costly than the introduction of Modification 116 or 116B. Both Modification 116 and 116B have similar low and negative net benefits. That is, adopting the amendments to Modification 116 envisaged by Modification 116B does little to improve the case for reform. It would be far less costly to retain the transitional arrangements indefinitely through adoption of Modification 116A.

Table 9.11
Comparison of Costs and Benefits (Net Benefits)

NPVs of Modification Proposals		**NERA Low Benefit Case**	**NERA Central Benefit Case**	**NERA High Benefit Case**
NERA Low Cost Case	Incremental Net Benefit of Mod 116A Compared to Transitional Arrangements	£0m	£0m	£0m
	Incremental Net Benefit of Mod 116C Compared to Mod 116A	-£26.96m	-£18.46m	-£9.96m
	Incremental Net Benefit of Mod 116 Compared to Mod 116C	-£67.96m	-£67.96m	-£67.96m
	Total Net Benefit of Implementing Mod 116 Compared to Transitional Arrangements	-£94.91m	-£86.41m	**-£77.91m**
	Incremental Net Benefit of Mod 116B Compared to Mod 116	£5.78m	£5.78m	£5.78m
NERA Central Cost Case	Incremental Net Benefit of Mod 116A Compared to Transitional Arrangements	£0m	£0m	£0m
	Incremental Net Benefit of Mod 116C Compared to Mod 116A	-£27.37m	-£18.87m	-£10.37m
	Incremental Net Benefit of Mod 116 Compared to Mod 116C	-£69.24m	-£69.24m	-£69.24m
	Total Net Benefit of Implementing Mod 116 Compared to Transitional Arrangements	-£96.62m	-£88.12m	-£79.62m
	Incremental Net Benefit of Mod 116B Compared to Mod 116	£5.78m	£5.78m	£5.78m
NERA High Cost Case	Incremental Net Benefit of Mod 116A Compared to Transitional Arrangements	£0m	£0m	£0m
	Incremental Net Benefit of Mod 116C Compared to Mod 116A	-£33.04m	-£24.54m	-£16.04m
	Incremental Net Benefit of Mod 116 Compared to Mod 116C	-£80.59m	-£80.59m	-£80.59m
	Total Net Benefit of Implementing Mod 116 Compared to Transitional Arrangements	**-£113.63m**	-£105.13m	-£96.63m
	Incremental Net Benefit of Mod 116B Compared to Mod 116	£7.17m	£7.17m	£7.17m

Table 9.12
Summary of Net Benefits of Modification Proposals

NPVs	Lowest Net Benefit Estimate	Highest Net Benefit Estimate
Incremental Net Benefit of Mod 116A Compared to Transitional Arrangements	£0.00m	£0.00m
Incremental Net Benefit of Mod 116C Compared to Mod 116A	-£33.04m	-£9.96m
Incremental Net Benefit of Mod 116 Compared to Mod 116C	-£80.59m	-£67.96m
Total Net Benefit of Implementing Mod 116 Compared to Transitional Arrangements	-£113.63m	-£77.91m
Incremental Net Benefit of Mod 116B Compared to Mod 116	£5.78m	£7.17m

10. Conclusion

Chapter 9 has described the questionnaire which NERA circulated to industry players and other interested parties, which asked for estimates of the costs and benefits of introducing Modifications 116A, 116C, 116 and 116B.

Chapter 9 also outlined the methodology we applied to extrapolate estimated costs to all industry players and interested parties resulting from the UNC modification proposals. Our extrapolations were based on the cost estimates submitted to us in responses to our questionnaire. We estimated costs which we would expect to be incurred by shippers, storage operators, TCCs and transporters.

We drew on the conclusions of the preceding chapter to compare the estimated costs of the various reform proposals with the relevant benefits. We showed that the net benefits of all modification proposals are negative. In particular, the net benefit in NPV terms of introducing Modification 116 varies between -£78 million and -£114 million depending on the cost estimation methodology. That is, in stark contrast to the findings of Ofgem's IA, we find that the costs of the enduring arrangements, envisaged by Modification 116, outweigh significantly the benefits produced by the proposed reforms.

We find that Modification 116A, which extends the transitional arrangements indefinitely, has the highest net benefit (in NPV terms) of all the proposed UNC modifications.

Modification 116C, which envisages the introduction of the flat exit capacity product and not the flexible exit capacity product, has the next highest net benefit, albeit a negative one. Imputing slightly higher benefits from the removal of regulatory risk might, in some cases, give it a positive net benefit.

The large step-up in costs due to the introduction of Modifications 116 or 116B rather than Modification 116C is attributable to the introduction of the flexibility capacity product. Respondents to our questionnaire believe it would generate large one-off and ongoing costs.

Modifications 116 and 116B have similar net benefits. Thus, adopting the amendments to Modification 116 envisaged by Modification 116B does little to improve the case for reform.

Although more costly than adopting Modification 116A, the introduction of Modification 116C generates a considerably higher net benefit in NPV terms than the adoption of either Modification 116 or 116B. However, our analysis implies that the costs of Modifications 116, 116B and 116C significantly outweigh the benefits gained through their introduction. It would be less costly to retain the transitional arrangements through adoption of Modification 116A.

The costs which would eventually be passed through to Irish energy consumers are not included in our analysis. However, their inclusion would significantly strengthen the case for maintaining the transitional arrangements through adoption of Modification 116A rather than adopting any of Modifications 116, 116B or 116C.

Appendix A. Ofgem's Impact Assessment

Although Modification 116 and its various alternatives and variants have been proposed by members of the industry, Ofgem has frequently indicated a favourable attitude to the reforms. Indeed, Ofgem imposed the current transitional regime as a condition of National Grid's sale of the Gas Distribution Networks in 2004.

In the context of the Transmission Price Control Review, Ofgem produced a draft impact assessment of the "enduring offtake" arrangements.[34] In this appendix, we comment on the reliability and significance of this impact assessment.

A.1. Comments on Ofgem's Approach

Ofgem has carried out its analysis in terms of the net benefit to consumers and so, at various points, has excluded costs which fall, in Ofgem's opinion, on other organisations. This approach reflects, we presume, the statutory obligation on Ofgem to take decisions that are in the interests of consumers, rather than to consider wider costs and benefits to society as a whole. However, as far as we are aware, there has been no legal interpretation of Ofgem's duty to protect consumers' interests or how it applies to impact assessments. In our view, it is short-sighted to assume that disallowed costs do not affect consumers because, even if the disallowed costs do not affect consumer prices in the short-run, the very act of disallowing them will raise prices to consumers in the long-run.

Suppliers of gas and network companies only remain in their respective businesses if they can earn a rate of return at or above the cost of capital, after recovering their capital and operating expenditures, so regulatory rules that routinely disallow some expenditures must find compensation through an increase in other allowances or in the cost of capital. In this sense, shareholders do not ultimately bear any costs. The observations that some costs will not *immediately* be passed through to customers is therefore misleading and understates the associated costs of the reform. It cannot be beneficial to consumers to promote measures that knowingly increase inefficiency.

Ofgem discounts costs and benefits at discount rates of 6% (representing a regulatory or commercial cost of capital) and 3.5% (representing a social discount rate). Ofgem does not attempt to justify the use of one rate or another, since it is not important for the results. In the following, for simplicity, we refer to the estimates using a 6% discount rate.

A.2. Benefits of "Efficient NTS Investment Signals"

Ofgem attributes substantial benefits (NPV = £37.6 million in the base case) to the reforms arising from greater efficiency in NTS investments and less risk of stranded costs. This estimate prompts several comments.

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[34] Ofgem (2006), Transmission Price Control Review: Initial Proposals, Appendix 17, Document 104d/06, Ofgem, 26 June 2006.

A.2.1. Nature of the proposed reform

First, Ofgem describes the source of the benefits on page 7 of the draft IA purely in terms of the benefits arising from introduction of *longer term* contracting arrangements for capacity. None of these benefits appear to flow from the *separation* of capacity into a daily average (flat capacity) and a daily swing (flex capacity). According to this analysis, therefore, these benefits would be achieved by any variant of Modification 116 which introduces long-term contracting.

Indeed, National Grid has stated that its investment policy has historically been – and will continue to be – driven by “end of day requirements”, i.e. by flat capacity.[35] National Grid has also stated that the system offers a total of 22 mcm of “baseline” flexibility capacity, whereas the maximum usage to date has been only 15 mcm.[36] Both these statements indicate that the introduction of flexibility capacity would produce no potential savings in investment.

A.2.2. Source of the saving

The IA presents a confusing description of the source of the savings in capex. Paragraph 1.25 says the following:

> *“We note that, by their nature, and as a result of informational asymmetries, such historical investment inefficiencies have been difficult to identify. Indeed, were they easy to identify ex post then the same benefits would be achievable via appropriate ex post adjustments by Ofgem at subsequent price controls and absent enduring offtake reform. However, we believe that the reforms proposed would help to reduce such informational asymmetries and the consequential efficiencies could therefore be significant.”*

The first sentence implies that information asymmetries prevented Ofgem from identifying inefficiencies. The second sentence says that overcoming this obstacle would have allowed Ofgem to disallow the costs of inefficient investments (i.e. allow “appropriate ex post adjustments by Ofgem at subsequent price controls”). The last sentence implies that Modification will overcome the information problem and allow Ofgem to identify substantial efficiencies. However, it is not clear whether Ofgem believes that the proposed arrangements will improve (1) the actual efficiency of NTS investment, or (2) Ofgem’s ability to identify and to disallow the costs of inefficient investment (without any actual improvement in efficiency). If Ofgem believes the savings arise because the Modification permits more cost to be disallowed, there will be no real gain in efficiency, merely a reduction in the amount of costs passed through to consumers in the first instance. Investors anticipating a more stringent policy on disallowances would demand a higher allowed rate of return on accepted investments in compensation. As a result, consumers would not benefit. (See above.)

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35 National Grid (2006), *Discussion Document: Modification Proposals to the Gas Transmission Transportation Charging Methodology, NTS GCD 02: Introduction of NTS Exit (Flexibility) Capacity and Commodity Charges under the enduring offtake arrangements,* National Grid Company, 20 October 2006, paragraphs 3.3-3.4.

36 See section 3.3.

Even if the supposed efficiencies are real, it is not clear whether Ofgem believes that the actual improvement in efficiency comes (A) from users giving National Grid better signals, or (B) from National Grid making better decisions due to a greater fear of disallowances by Ofgem. Each is open to dispute.

A.2.3. Alternative sources of long-term commitment

Any improvement in signals from users derives from the longer term financial commitment required by users, who must book capacity several years in advance. Such long-term commitments would be possible under the current regime, though the use of ARCAs.

Ofgem's recent decision on Marchwood seems to have ruled out the use of long-term ARCAs. The reasoning in that decision is somewhat curious, since Ofgem argues that it would be discriminatory to demand long-term commitments from new users (or, presumably, existing users who request additional capacity) as long as existing users make no commitment beyond one year. However, this definition of discrimination seems uncommonly strict.

In practice, new users impose a need for new investment, whilst existing users are served with existing assets whose costs are sunk (at least if they don't increase their demand). This objective difference between new and existing users could have justified the difference in treatment. Given the large potential benefits from long-term commitments – and Ofgem's oft-stated determination that decisions should not fetter regulatory discretion – recognition of these large potential gains might easily justify a change in Ofgem's approach to ARCAs. ARCAs would then achieve many of the benefits attributed to Modification 116.

Thus, the benefits attributed to the modification, relative to the current system, seem to derive from a temporary and questionable regulatory constraint, i.e. the recent limitation on the length of commitment in ARCAs.

A.2.4. Effect of "longer" commitments

Although long-term commitments can in some conditions improve the efficiency of investment, aspects of the proposed enduring arrangements suggest that the gains will not be large.

§ First, there is a fundamental problem with the separation of entry from exit capacity, a tariff policy which Ofgem adopted in the 1990s in order to facilitate competition in the gas market, rather than efficiency in the national grid or national transmission system.

Even if users commit to a certain level of exit capacity, that commitment is not linked to any entry point. National Grid is therefore free to decide which route through the network needs to be reinforced, based on National Grid's own forecast of gas flows. Lengthening the commitment to exit capacity will not improve the efficiency of National Grid's choices in this respect.

§ In addition, neither ARCAs nor Modification 116 require users to enter into a commitment to pay the whole cost of any capacity reinforcement over the whole life of the assets, so neither system presents users with the full cost of their decisions.

The only effect of Modification 116 (given the artificial constraint on the length of any ARCA) is to extend the period for which the user is committed to pay for capacity by a few years. However, the primary commitment by the user remains the irreversible cost of constructing the facility that takes the gas. Once someone has built a power station or a factory, it is likely to continue using gas for a period longer than that covered by the commitment to pay for gas transmission capacity. Hence, the true signal to construct pipeline capacity lies in this construction of a connected facility, as before.

§ Intrinsic to the proposal is the replacement of interruptible capacity with firm capacity and provision for NGC to buy-back capacity, so demands for firm capacity need not indicate either a desire for peak capacity or a need for investment.

NGC will still have scope to decide whether or not to invest to meet peak capacity requirements, but will have to do so in the basis of a forecast of which users will be prepared to sell back capacity and for how much – a more subjective and uncertain basis than the current division between firm and interruptible users.

Overall, Modification 116 does not provide efficient signals for construction of pipeline capacity, since it does not require users either to identify properly the route over which new capacity is required, or to commit to pay all the associated costs. Making good this lack of signals relies on the forecasts and discretion of National Grid, just as at present. Hence, there is no real basis for saying the Modification 116 will improve the efficiency of capacity investment decisions.

A.3. Scale of the Forecast Capex Saving

Ofgem's IA adopts a figure of 6.5% of forecast capex for the proposed saving in capex. However, this figure is derived from estimates in previous documents, which turn out on inspection to be little more than working assumptions that (so far) have not been challenged. It may be difficult to quantify precisely the benefits arising from the proposals (although more work could be done to clarify the source of such benefits), but Ofgem's approach would at least need to be transparent and consistent. Unfortunately, Ofgem's approach raises a number of doubts on this score and requires urgent attention.

Ofgem attributes[37] the figure of 6.5% of forecast capex to an estimate prepared for the Final IA of the sale of the gas distribution networks. It comprises 3.5% for a reduction in capex for NTS exit capacity and a further 3% from "the removal of long-run NTS interruption inefficiencies".[38] Each item begs a number of questions, as discussed below.

A.3.1. Basis for saving in NTS exit capacity capex

The first of these figures "is based on the *assumption* that 3.5% of NTS exit capacity related capex could be saved on an annual basis as a result of improved efficiency signals"[39] (*NERA*

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[37] Ofgem (2006), page 8, footnote 3.

[38] Ofgem (2004b), *Potential Sale of Gas Distribution Networks Businesses, Final RIA, Appendices*, Ofgem 255/04b, November 2004, pages 79 and 86.

[39] Ofgem (2004b), para 9.15, page 79.

emphasis). A footnote to this paragraph states that "The analysis undertaken is based on data extracted from NTS exit capacity capex provided by Transco, relating to the period 2005-2012. Following Transco's suggestion, it is assumed that annual NTS exit capacity over the period 2013 – 2022 equals the average of the period 2005 – 2012 (i.e. £12.4 per annum)."[40] There are several problems with the approach that Ofgem has adopted:

- These comments provide no justification for the assumed rate of capex saving of 3.5% (nor any indication of another possible source for this figure).
- Ofgem's 2004 estimate of "NTS exit capacity capex" of £12 million per annum is much lower than the figure of £65 million per annum that Ofgem uses in 2006. Ofgem offers no explanation as to why this figure should have increased more than five-fold in two years.
- Ofgem does not consider whether the capex saving rate of 3.5% is still applicable to the higher figure, even though the higher figure may include assets that offer different potential for savings. Some of the saving would have been achieved by the application of the transitional arrangements to the GDNs,[41] which cover about 60% of total exit capacity.

Hence, Ofgem's estimate only refers back to an earlier assumption, which does not appear to have been objectively justified. Several important factors have changed since Ofgem made that assumption, including the level – and probably the definition – of forecast capex in NTS exit capacity, and the transitional arrangements applied to GDNs. Each of these changes should have led to a review (and most likely a reduction) in the applicable percentage.

A.3.2. NTS interruption inefficiencies

The rate of capex saving from the removal of "NTS interruption inefficiencies" is even less well justified. It appears to derive from an assumption made for the regulatory impact assessment of the interruptibility arrangements.

> *"After allowing for the fact that some capital expenditure, even if inefficient, is likely to deliver some value to customers, Ofgem considers that sharper investment signals and more flexible contracting arrangements for interruptible services could deliver benefits to customers of at least 3% of capital expenditure per annum."*[42]

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[40] Ofgem (2004b), footnote 57, page 79.

[41] Paragraph 9.15 of Ofgem (2004b) says "Under DN sales, the proposed framework would therefore deliver more efficient signals for investment, *particularly* in relation to NTS direct connects." (NERA emphasis) In other words, not all these benefits would have come from TCCs and so not all can be attributed to Modification 116.

[42] Ofgem (2004a), *National Grid Transco – Potential Sale of Gas Distribution Network Businesses Interruptions Arrangements: Regulatory Impact Assessment*, Ofgem 146/04, June 2004, para 1.33, pages 90-91.

This assumption, along with the estimate of future capex, is carried forward into Ofgem's impact assessment for the sale of the GDNs:

> *"NTS exit capacity capex is assumed to be £12m per annum in current prices; and sharper investment signals and more flexible contracting arrangements for interruptible services are assumed to deliver benefits of at least 3% of capital expenditure per annum."*[43]

Ofgem then carries forward the percentage to its latest IA of the enduring offtake arrangements, but applies it to the much higher estimate of NTS exit capacity capex (£65 million pa).[44]

These figures may not have been challenged in the context of the sale of the GDNs, but require urgent reassessment. In the first place, it is not clear how the change in interruptibility arrangements will improve the efficiency of capex. Any user who wants interruptible capacity can take it on request at present, whereas under Modification 116 users would have to take firm capacity and sell it back to NGC. NGC will therefore have to forecast which users would be prepared to sell back capacity and at what price. These forecasts may be no more accurate or efficient that the current signals provided by users' choices. The basis for the saving is therefore entirely opaque.

Moreover, the figure of 3% related to forecast capex of £12 million pa; there is no guarantee that the same percentage applies to the much higher (and presumably redefined) level of £65 million pa. The higher figure may represent a redefined concept of investments related to exit capacity, perhaps covering reinforcements located "deeper" within the network. The link between users' requests for capacity and these "deeper" reinforcements will be more tenuous. Hence, any savings associated with a change in users' requests due to Modification 116 (if that is the source) will have less impact on these investments than on the cost of "shallower" reinforcements. That implies that the assumed figure of 3% should be lower.

A.3.3. Conclusion on the scale of potential capex savings

Ofgem's estimate of the potential capex savings derives from parameters set out in earlier documents, but must be counted as unreliable.

Nowhere in the documents we have reviewed is there any detailed explanation of the real source of the efficiency gains, i.e. a description of how the new arrangements will change the behaviour of National Grid and users of the NTS. Ofgem refers to abstract benefits of longer term commitments, but these commitments will not cover either the route of new gas flows from entry to exit, nor the full life or costs of the associated investments. Future efficiency will still depend heavily on the judgement of National Grid. Moreover, these references to longer term commitments do not assign any benefit to creation of a new service for "flexibility" capacity.

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[43] Ofgem (2004b), para 9.41, page 86

[44] Ofgem (2006), table 17.3.

Ofgem's forecast rate of capex savings remains no more than a working assumption. That working assumption may not have been challenged when it was used to assess the sale of the GDNs, but several factors have changed since then. Ofgem does not scale down the rate of potential savings to allow for those achieved since by the application of the transitional arrangements to the GDNs. Moreover, Ofgem has dramatically raised the level (and, we believe, changed the definition) of the capex forecast to which the rate is applied, without considering whether the rate should be redefined.

Given the lack of concrete analysis behind Ofgem's figures, it is difficult to review Ofgem's assumptions. However, enough has changed since the initial estimate of the rate of capex savings to suggest that is should be reviewed and that a consistent approach would have led to a much lower figure. In the meantime, we believe that it would be safer *either* to attribute no benefit to the new arrangements (because the new arrangements will not affect National Grid's responsibility for making key investment decisions) *or* to calculate a lower rate of benefits derived from the difference between the capex forecasts of £12 million pa and £65 million pa, on the grounds that much less of the additional exit capacity is user-specific and determined by user commitments, whilst the rest is still dependent upon judgements by National Grid.

There is no objective way of revising Ofgem's estimate (since it is not derived from detailed objective analysis in the first place). Table A.1 shows how Ofgem's estimate of £20.2 million would fall to only £12.0 million, if the capex savings rate on the extra capex were 1.75%, half what Ofgem assumed for the original level of capex.

Table A.1
PV Adjusted for Lower Rate of Savings: NTS Investments

Source	Capex Saving (£ million pa)	Savings Rate (%)	Savings (£million PV)
Ofgem 2006	65	**6.50%**	37.5
Pro Rata	**65**	**3.50%**	20.2
Ofgem 2004a	**12**	3.50%	**3.7**
Difference	**53**	1.75%	**8.2**
Summation			**12.0**

Ofgem's estimate of the savings from efficiency in interruptions relies on equally unreliable assumptions, without any adequate explanation of the source in changed behaviour. A similar adjustment would take the estimate from £17.3 million to £10.3 million, as shown in Table A.2. However, further consideration is required to assess how much of these benefits apply to interruptions of users attached to the GDNs and hence already covered by the transitional arrangements.

Table A.2
PV Adjusted for Lower Rate of Savings: Interruptibility

Source	Capex Saving (£ million pa)	Savings Rate (%)	Savings (£million PV)
Ofgem 2006	65	**6.50%**	37.5
Pro Rata	**65**	**3.00%**	17.3
Ofgem 2004a	**12**	3.00%	**3.2**
Difference	**53**	1.50%	**7.1**
Summation			**10.3**

Thus, even these adjustments reduce the potential saving from £37.6 million to £22.3 million, or less, if the source of the savings cannot be adequately explained, or if some is already covered by the application of the transitional arrangements to the GDNs.

A.4. Non-Discriminatory Allocation of Capacity Products

Ofgem attributes a base case benefit of £21 million (present value) to the avoidance of discrimination. The explanation of this benefit is insufficient, however, to justify any positive figure. Ofgem's IA lists several supposed sources of efficiency gains, but none bear closer scrutiny.

Paragraph 1.35 suggests retained GDNs might receive a favourable allocation of long-term exit capacity rights. However, under the transitional arrangements, there is no long-term allocation of exit capacity rights. It is therefore not clear whether this statement refers to the effect of implementing the enduring arrangements (or Modification 116), given that the transitional arrangements are already in place.

Paragraph 1.36 suggests that the retained GDNs would benefit by avoiding investment, due to receiving "favourable treatment" in the booking of long-term capacity. We presume that this means retained GDNs would receive a share of National Grid's flexibility. However, it would only be in National Grid's interest to do this if it achieved an overall saving, taking into account both the NTS and the retained GDN. Such a decision would be efficient, unless another GDN could offer a larger overall saving and was willing to more than compensate National Grid for the loss of its own saving. The benefit would be the difference between the two investment plans (not the overall saving on the retained GDN). Moreover, if both investments were efficient, National Grid ought to proceed with both. Hence, such potential benefits are very small.

Paragraphs 1.35 and 1.36 also refer to Ofgem's view that the benefits to customers relate to avoiding payments to National Grid under its various capex and opex incentive schemes. However, payments under these schemes only cover a small proportion of the capex involved in any saving, i.e. the annualised depreciation and return for a few years, not the total capex saving. Moreover, as discussed in section A.1, these costs and savings are not immediately passed through to consumers, but affect the overall willingness of investors to supply capital, and so feed into future costs. To count benefits on the grounds of immediate incidence is short-sighted and misleading.

Finally, paragraph 1.39 piles one unreliable assumption upon another. Ofgem assumes, without any justification, that potential discrimination will reduce the potential benefits of the GDN sale by 5%. However, those potential benefits derived entirely from Ofgem's assessment of the supposed benefits of benchmarking or comparing GDNs, which themselves had no basis in observable fact, accepted theory, or general experience.

These estimates of potential benefits, which form the majority (£21.0 million) of forecast capex savings, are therefore based on entirely subjective and unsupported assumptions. More seriously, they rest upon the assumption that the new arrangements will reduce or eliminate the potential for National Grid to discriminate between different users. However, National Grid will still possess the ability to discriminate by other means, namely in its decisions over when to buy-back firm exit capacity and how much to pay for it. Since National Grid's transactions with the GDNs cannot be conducted by a competitive auction (since only the GDNs use the exit capacity concerned), National Grid will be able to achieve all of the effects described in paragraphs 1.35 to 1.39 by paying its retained GDNs more for buying back capacity when they do not need it, whilst offering independent GDN fewer such opportunities. Thus, the whole basis for Ofgem's estimate of benefits appears to be spurious.

A.5. Reduced Incidence of ARCAs

Ofgem assigns a benefit of £10 million to the avoidance of disputes over ARCAs. However, the analysis makes no allowance for these costs to be replaced by other forms of dispute. For instance, terms that were formally discussed in the context of an ARCA might simply re-emerge in the form of disputes over NExAs. Alternatively, the complexity of the new arrangements may increase the costs of scrutinising and challenging National Grid's assumptions over the allocation and pricing of the new products. Since disputes over general tariffs will involve all users (cf. the discussion of Modification 116), whereas disputes over ARCAs concern only the involved parties, the new system could actually increase the cost of disputes.

This item amounts to only £0.9 million per annum, but if there were 16 shippers (see paras 1.78 and 1.86 of Ofgem(2006)), each would have to incur costs of only £56,000 per annum, or approximately half of one full-time employee, on average to offset this benefit entirely. Given the complexity of the scheme, this seems like a plausible outcome. This benefit should therefore be substantially reduced (e.g. by half, to £5 million) to allow for the offsetting costs of other disputes.

A.6. Conclusion on Benefits

Ofgem assigns benefits with a PV of £68.5 million to the enduring arrangements, comprising £37.6 million for capex efficiencies, £21.0 million for preventing undue discrimination and £10 million for the abolition of ARCAs. The adjustments set out above would dramatically reduce these figures, possibly to zero since Ofgem has not clearly established the existence and source of the benefits. Allowing for the existence of these benefits, the adjustments above give:

- Zero to £12 million for capex efficiencies;
- Zero to £10 million for interruptibility savings;

- Zero for reduced discrimination (since discrimination is just as possible under the new arrangements); and
- Zero to £5 million for the avoidance of disputes over ARCAs.[45]

Some of the benefits that Ofgem attributed to the enduring arrangements date back to the assessment of the sale of the GDNs and therefore include savings that have been achieved already under the transitional arrangements. These figures do not make any allowance for further adjustment on this basis, which would reduce them even further. Moreover, the supposed £10 million benefits attributed to the changes to interruptibility are extremely dubious, and merit a value close to zero (unless anyone can provide a detailed explanation as to why the buy-back arrangements should promote greater efficiency than interruptibility). Hence, any final impact assessment of Modification 116 and its variants would have to omit the effects of any changes already made under the transitional arrangements.

A.7. Discussion of Costs

We have updated our own survey of costs and so need not refer to Ofgem's figures, which in any case cover the "enduring arrangements" in general, rather than the various proposed modifications. However, the cost estimates merit some comment.

A.7.1. Costs to shippers and transmission connected customers

Ofgem discusses its cost estimate for shippers in paras 1.80-1.102. At the 6% discount rate, Ofgem gives these costs a present value of £11-12 million, assuming that costs are proportional to the size of a shipper (measured by either number of offtakes or volume of throughput). Ofgem also considers an alternative basis in which the lowest cost response from a shipper is taken as an indication of fixed costs (incurred by each of 16 shippers). On this basis, Ofgem calculates a total cost of £19 million. These estimates are highly subjective, however, being based on a manipulation of the data that is not justified on statistical grounds.

Ofgem received responses from five shippers in all and shows the present value of their costs estimates per offtake in Figure 17.1. For the five shippers, this present value per offtake comes out with a wide range of estimates, with three around £100, one at roughly £600 and one at roughly £900. Ofgem chose to exclude both the highest estimates, on the grounds that (1) they may be inaccurate and (2) shippers may only be able to pass through the costs of a "typical shipper". However, such choices are utterly arbitrary:

- Even if there is uncertainty over the total level of costs, uncertainty provides no reason for excluding the highest estimates – in a small sample of five observations, one might equally conclude that the *lowest* estimates were inaccurate. An unbiased estimate (in the absence of any information on which way the inaccuracy lies) would take the overall average of all the observations.
- In a competitive market, prices depend on marginal costs, i.e. the costs of the highest cost operator in the market,[46] so one cannot presume that high cost suppliers will be unable to

[45] Ofgem 2006 also describe the source of this saving as "clear and appropriate accountability and responsibility" in table 17.7 on page 17.

pass through all their costs. To determine what costs will be passed through, Ofgem would need to carry out an analysis of market behaviour, identifying who is at the margin and which suppliers possess market power.

Ofgem's so-called "cluster analysis" is therefore biased and subjective. A less biased approach would be to accept that there is great uncertainty over future costs (as indicated in paragraph 1.101), but that each supplier's cost figure is an equally likely estimate of the true costs. This approach would justify taking an average of all the data. Doing so would raise Ofgem's estimate of shipper costs by a factor of about three. Even just including the lowest four observations would double Ofgem's estimate. Thus, Ofgem's adoption of a biased approach has led to a substantial underestimate of costs.

Ofgem discusses the costs to transmission connected customers (TCCs) in paras 1.103-1.109 and concludes that the present value of such costs would be £7 million. (The level of detail provided in the description of the analysis does not provide any basis for commenting on this number.) Ofgem adds it to the costs to shippers to derive the total cost to customers. The estimates using a 6% discount rate are shown in Table A.3:

Table A.3
Ofgem Estimate of Shipper and Customer Costs (6% discount rate)

Method of Extrapolation	Offtake (A)	Throughput (C)	Fixed+Variable (B)
Shipper estimates "with clustering analysis"	19.1	18.3	26.0
Shipper estimates "without clustering analysis"	35.1	33.2	33.5

From these results, we draw two conclusions. First, Ofgem's selective use of data ("clustering analysis") had a major impact on results. Second, the choice of Offtake or Throughput to extrapolate from respondents' figures to figures for the industry as a whole did not have a major impact on the results. For our own estimates, we have used throughput and exit capacity.

A.7.2. Costs to gas transporters

Ofgem records the costs incurred by gas transporters in paragraphs 1.110-1.114 and derives a range of £20.0-24.5 million. Ofgem received responses from four GDNs and, as with responses from shippers, decided to exclude evidence from the most expensive respondent. Ofgem describes this respondent as a "significant outlier", but Figure 17.2 shows the responses in cost per Offtake scattered almost uniformly over the range £100-250. The decision to exclude the uppermost response is therefore entirely arbitrary and biases the result. Including all observations as equally accurate would raise the average cost by about 20%, therefore lifting the range of total costs to £24.0-29.5 million, as shown in Table A.4.

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[46] Note that this short-hand rule of market behaviour is not conditional on the marginal provider in the market being "efficient" by any standard other than it having lower costs than the next most expensive provider.

Table A.4
Ofgem Estimate of Transporter Costs (6% discount rate)

GDN Costs	Lower	Upper
GDN estimates "with clustering analysis"	20.0	24.5
GDN estimates "without clustering analysis"	24.0	29.5

Ofgem adopts the view that these costs should be excluded from its impact assessment, as "costs associated with the implementation of enduring offtake arrangements should not be passed through to customers as such costs represent a cost of the GDN sales transaction."[47] This point is debatable, as National Grid would not have undertaken the sale without being able to recover the costs from higher profits (than otherwise) for some part of its business.[48] We have collected responses from the GDNs on the costs imposed on them by Modification 116 and its variants.

A.8. Conclusion

Ofgem's assessment of the impact of the enduring arrangements contains highly subjective and, in some places, entirely arbitrary decisions about what should be included. Since they are so subjective, they are often difficult to appraise, but some clear biases are evident.

First, Ofgem has overstated capex savings by applying to a high level of capex (£65 million pa) a cost savings rate of 3.5% that was only ever applicable to a lower level of capex (£12 million pa) – and was highly subjective to begin with. Reassessment of this rate on some objective basis is required urgently. In the meantime, it would be safer to assume that the enduring arrangements will achieve on the additional capex at a much lower rate (e.g. 1.75% instead of 3.5%).

Second, Ofgem assumes without analysis that the new arrangements will remove costs caused by (1) National Grid's ability to discriminate and (2) the avoidance of disputes over ARCAs. However, Ofgem has not shown that National Grid would engage in discrimination, or how that would lead to lower costs, or why National Grid cannot use its discretion under the enduring arrangements to discriminate in different ways. The value placed on this item is therefore so dubious that we believe it must be ignored. These adjustments reduce the benefits of capex efficiency to about £17 million. The effect of reducing discrimination would be something much less than Ofgem's estimate of £20 million, putting benefits in range £25-30 million.

Similarly, Ofgem has understated the costs of implementation by excluding responses without having any objective basis for doing so. The so-called "cluster analysis" is nothing

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47 Ofgem (2006), para 1.110, page 27.

48 For example, National Grid may have anticipated that the separation would provide a better chance of Ofgem allowing recovery of its total investment costs, or that the separation would introduce new more focused management that would achieve a lower level of costs. The latter benefit would, in principle, be capitalised in the sales price of the GDNs, but only to the extent that bidders expected to be able to keep their cost savings.

more than a biased selection process. As a result, the costs to shippers would to two to three times higher, whilst the costs to GDNs would be 20% higher.

Ofgem has decided that some costs should be ignored because they do not fall on consumers in the first place. (Ofgem ignored costs falling outside its jurisdiction for the same reason.) Such an approach is also dubious, since investors require a rate of return equal to the cost of capital over and above the capital and operating expenditures, so any disallowed costs need to be compensated by a higher rate of return. Only the recovery of the GDNs' costs, which Ofgem associates with the sales process, might fall outside this rule, if the potential for recovering them derives from greater management efficiency capitalised in the sales price.

Removing Ofgem's arbitrary adjustments increases the cost of implementing the enduring arrangements to £33-35 million, even before allowing anything for the costs of transporters or foreign respondents.

The crucial point is that even these simple adjustments for bias produce a negative NPV, with benefits being outweighed by costs – even before allowing anything for transporter costs.

A.9. Coda: Ofgem Comment on NERA/TPA Report

Appendix 17 to Ofgem (2006) contains an annex that responds to an earlier report written by NERA Economic Consulting and TPA Solutions in 2005, on similar proposals to reform the exit capacity arrangements. The following section provides a brief response to those comments.

A.9.1. Interruptible Customers, free-riding and cross-subsidies

Ofgem takes issue with the NERA/TPA point that there is no cross-subsidy inherent in interruptible tariffs. Ofgem's counter-argument is that "users may receive different levels of service for the same discount to NTS exit capacity charges as the probability of interruption may vary significantly by location."[49] Ofgem notes that some interruptible sites could be served on a firm basis and that, "if interruptible services were to be price in accordance with the probability of interruption, one might expect such services, in many cases, to be priced at or close to the firm price."[50]

Ofgem's response confuses the costs of providing a service with the value of the service to the user. As long as a user is prepared to be interrupted whenever capacity is scarce, it does not impose any cost of building capacity on the network, *regardless of how often it is interrupted in practice*. Hence, a cost-based charge for interruptible service would not vary in relation to the probability of interruption. Ofgem may have in mind some kind of alternative tariff system based on willingness-to-pay – i.e. the idea that users who are not interrupted ought to be willing to pay the full cost of firm capacity. However, it is not possible to define a cross-subsidy by comparing a cost-based charge with willingness-to-pay. Otherwise, virtually all customers paying a cost-based charge would be in receipt of a cross-subsidy, since they only consume services for which they are willing to pay more than the

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[49] Ofgem (2006), Appendix 17, Annex 1, para 1.154, page 39.

[50] Ofgem (2006), Appendix 17, Annex 1, para 1.156, page 39

charge. This argument is therefore based on an illogical view of cross-subsidy which renders it nonsensical.

Ofgem also points out that users can switch from firm to interruptible capacity, thereby potentially avoiding the costs of paying for capacity. Such an argument has little to do with cross-subsidy or discrimination, since the users would still only be paying a cost-based charge. Instead, this fear concerns the potential efficiency gains arising from long-term commitments and investment signals, which are covered separately.

A.9.2. GDNs/TCCs

Ofgem's discussion of this item notes our prediction that there will be no transparent way of setting a tariff for flexibility capacity, but does not deal with it at all, except to note that National Grid has promised to develop a transparent model. We look forward to seeing this model, and reiterate our prediction that it will not derive charges in an objective and transparent manner.

Ofgem refers to a discussion of different proposals, including that of extending flat capacity booking to GDNs. Ofgem refers to National Grid's response that models without a flexibility product would require a bigger system. We find this comment hard to reconcile with National Grid's admission that so far the maximum use of flexibility has been 15 mcm, compared with an available capacity of 22 mcm, and with National Grid's statement that investment policy is driven by daily requirements.

A.9.3. RDNs/IDNs

Ofgem's comments focus on our suggestion that the interim arrangements remove the basis for National Grid to discriminate between GDNs. Ofgem adopts the transitional arrangements as the appropriate starting point, but this difference need not concern us. Ofgem's point is that there is potential for discrimination in the negotiation of ARCAs.

The proposed Modification 116 and its variants still provide scope for discrimination through (1) National Grid's allocation and pricing of exit capacity buy-back, (2) the lack of transparency in setting charges for flexibility capacity and (3) the remaining areas for site-specific negotiation, such as NExAs.

A.9.4. Unintended consequences

We welcome Ofgem's recognition of the unresolved issues and the efforts made to resolve them. Inevitably, several detailed points have yet to be resolved. Our concern, however, lies in the fear that it will be impossible to resolve these issues objectively and transparently, because the division of maximum deliverability into daily flat and flexibility capacity is not related to the underlying cost function.

A.9.5. Cost-Benefit Analysis

We note Ofgem's effort to update the cost-benefit analysis. The comments provided above address most of the points raised in this section of the annex. One technical point arises from Ofgem's statement that "We continue to believe that, in the event of constraints in the availability of flexibility capacity, there may be benefits in this area." It is hard to argue that there are no benefits from efficient rationing of a scarce commodity (flexibility capacity), “in the event of constraints in [its] availability”. However, so far National Grid’s figures do not indicate any constraints on use of flexibility capacity, which implies that such benefits do not exist.

A.9.6. Costs

Ofgem criticises NERA for not undertaking any cluster analysis. In practice, we regard such selection of favourable data as a biased method of appraisal, as outlined above. In practice, we found only one outlier, which we gave special treatment, but did not remove entirely from our analysis.

Ofgem notes that we did not engage with the industry in detailed discussion of the data. In practice, the timetable for response did not permit such interaction (except with the project sponsors). The same tight timetable applies to this submission. In any case, NERA does not have the same power to request information as Ofgem and so it would be difficult to investigate data in the same way. We are pleased that Ofgem has had a chance to discuss these costs with the industry and hope that there is time in the regulatory process for similar discussions this time around. However, such discussions would only be useful if Ofgem is able to apply rigorous and objective standards when reviewing the data. The standards in Ofgem (2006) fall short of any reasonable attempt to investigate or appraise the submissions.

NERA (and no doubt others) would be keen to help with this appraisal. Short of accompanying Ofgem in its enquiries, the most useful method would be for Ofgem to record (1) what additional information was acquired from such meetings; (2) what this information means for specific cost estimates; and (3) how Ofgem has used this information to adjust the cost estimates. In Ofgem (2006), the actual adjustments made by Ofgem are far removed from this kind of transparent analysis.

Appendix B. Questionnaire

The Gas Forum has commissioned NERA to analyse the proposed changes to the NTS exit and interruptible regime. Our work will update an impact analysis which we completed in June 2005. We would appreciate your assistance in developing this analysis and, where possible, quantifying the costs and benefits. When this work is completed, it will be submitted to the Gas Forum and may be published and/or circulated to industry participants.

We have listed all our questions in this document, but have attached a spreadsheet form into which you should enter your answers. If you have any questions regarding the questionnaire, please do not hesitate to contact Richard Druce at NERA on 020 7659 8540. Please send your response by close of play on **Friday 17 November 2006**.

At the top of the spreadsheet, we ask you to enter a few details about yourself.

- Company name
- Name of respondent
- Contact number
- Contact email
- The business activity of the respondent:
  - Please select one or more from the following: shipper, transporter, consumer, interconnector, storage, GDN, other (please specify).
  - Enter data in a single spreadsheet but, if you can, enter separate costs and benefits for each activity in the notes column

To help us put your answers in perspective, we ask you to indicate total exit capacity and throughput figures per annum for this business activity, broken down between exits to Direct Connects (DCs) and exits from Distribution Networks (DNs), and between firm and interruptible capacity.

We realise that any information you give us may be highly confidential. We will treat all information given to us in strictest confidence. We will not disclose any information provided by questionnaire respondents to anyone outside the NERA project team without prior permission, except in either anonymised or aggregate form. The data you send will be kept on file until the end of the project, unless you request otherwise. Please indicate what level of confidentiality you require by stating whether you agree with the following or not:

- inclusion of the company name in an appendix to our final report listing respondents.
- inclusion in our final report of anonymised cost and benefit data.
- inclusion in our final report of anonymised extracts from statements made in the questionnaire.

B.1. Introduction

Ofgem and National Grid Gas NTS consulted widely on possible reform of NTS exit arrangements in the lead-up to the sale of the four independent distribution networks (IDNs). Ofgem's Regulatory Impact Assessments (IAs) on offtake and interruptions arrangements in summer 2004 concluded that there was the need for market-based mechanisms to allocate NTS exit capacity, flow flexibility and interruption rights. However, to date, reforms have only covered NTS offtake arrangements for distribution networks operators (DNOs). Ofgem consulted further on reform of NTS offtake arrangements during the Transmission Price Control Review (TPCR) and published a further draft IA in June 2006. The June 2006 IA compares the costs and benefits of the "enduring arrangements", which Ofgem hopes to implement, with the "transitional arrangements", which are currently in place.

B.1.1. Transitional Arrangements

Since 1 May 2005, National Grid has made exit capacity available on the basis of a Maximum Daily Quantity. The maximum hourly rate of offtake is 1/24th of the Maximum Daily Quantity. Network Exit Agreements (NExAs) define the limits on rates of change in flow.

The transitional arrangements created a new contractual interface between National Grid and the DNs and introduced two new products:

- flat capacity (defined by a daily maximum offtake); and
- flexibility capacity (measuring the amount of variation across the day).

The transitional arrangements introduce flat and flexibility capacity rights for DN Operators at NTS/DN exits, and a process for allocating this capacity. For NTS/DN exits, shippers pay exit capacity charges based on downstream capacity holdings.

The transitional arrangements did not extend these products and processes to shippers delivering gas from the NTS to Transmission Connected Customers (TCCs), i.e. to customers connected directly to the NTS at Connected System Exit Points or "CSEPs", which include interconnectors. At such exit points, shippers must buy a single product, "NTS Exit Capacity", on behalf of their customers. At CSEPs, National Grid makes NTS Exit Capacity available on an interruptible basis on request and shippers book NTS Exit Capacity on a 12-month rolling basis, through a process that requires them to signal proactively any desire to renew their capacity rights. At other offtake points, capacity is booked automatically at the registered capacity of the supply point.

The transitional arrangements do not allow users to book existing capacity for periods beyond investment lead times. For incremental capacity and new connections National Grid extracts commitments from users through Advanced Reservation of Capacity Agreements (ARCAs).

B.1.2. Proposed Modifications

In the last two years, Ofgem and National Grid have consulted on and developed new business rules that define a proposed new exit regime. NGC has submitted these new rules as Modification 116 (Modification 116) to the Uniform Network Code (UNC). Modification

116 would award existing holders their "Prevailing" level of exit capacity in 2007. Then, each July beginning in 2007, holders could apply to increase their "Prevailing" exit capacity, but only for gas years Y+4 to Y+7 (i.e. from October 2010 at the earliest). Holders could apply to reduce their "Prevailing capacity" subject to a minimum advance notice defined by the longer of (a) four years after the last increase or (b) fourteen months (e.g. by giving notice in July 2009 to reduce capacity from October 2010). From 2007 onwards, National Grid would also hold annual and daily auctions of exit capacity that was available but not already allocated to shippers.

Three signatories to the UNC have forwarded alternative modification proposals, which are to be considered alongside the core proposal. We summarise Modification 116 and the three alternatives (116A, 116B and 116C) in the relevant sections of this document. For the sake of clarity, we have put these alternative modifications in a different order (116A, 116C, 116, 116B) that allows you to see the incremental effect of each. The questionnaire is therefore structured as follows:

§ Section 2 covers the effect of continuing with the “transitional arrangements” (116A);

§ Section 3 covers the effect of introducing a ***flat*** capacity product (116C);

§ Section 4 covers the effect of introducing ***flat and flexibility capacity*** products (116);

§ Section 5 covers proposed ***refinements*** to the flat and flexibility capacity products (116B).

We end with some questions about the general background to these modifications:

§ Section 6 requests your views on the allocation of entry capacity; and

§ Section 7 requests your views on other issues and an overall evaluation of the proposed reforms.

We very much hope that you will take a little time to answer this questionnaire and to send your results to us. Please email your completed spreadsheets to <Anne.Fane@nera.com> by the close of play on Friday 17 November 2007. We would like to thank you in advance for your assistance.

B.2. Maintaining “Transitional Arrangements” (Modification 116A)

B.2.1. Details of Modification 116A

Modification 116A proposes that the transitional arrangements currently in place should be continued indefinitely. Modification 116A achieves this aim by removing the “sunset clauses” currently in the UNC that limit the life of the transitional arrangements to 30 September 2010. The “transitional arrangements would not therefore lapse automatically at any time in the future. Under Modification 116A, National Grid would continue to release and allocate Exit Capacity, through the transitional arrangements, far enough in advance to allow any physical expansion of the network necessary to match allocated exit capacity.

B.2.2. Questions

1. What **benefits** would you expect to derive from the extension of the transitional arrangements, as envisaged in Modification 116A, *compared with the situation where the transitional arrangements are subject to a "sunset clause"*? Please quantify where possible.
2. What are the likely **one-off costs** (e.g. IT costs, staff recruitment or training costs, etc) you would incur, as a result of extending the transitional arrangements as envisaged in Modification 116A?
3. What are the likely **ongoing costs** (e.g. transaction, risk management or accounting costs, etc) you would incur as a result of extending the transitional arrangements as envisaged in Modification 116A?
4. Apart from any additional costs you may incur, do you foresee **any other disadvantages** of extending the transitional arrangements as envisaged in Modification 116A, such as operational difficulties for your business or others?

B.3. Introducing Flat Capacity (Modification 116C)

B.3.1. The Flat Capacity Product

The flat capacity product envisaged under the "enduring arrangements", defines the maximum quantity that may be taken over a day at an individual exit point. Under Modification 116, users requiring variable within-day flow rates would need to acquire both flat and flexibility capacity. However, Modification 116C proposes *only* the introduction of the flat capacity product.

The flat capacity product is common to Modifications 116C, 116 and 116B. Existing users would receive flat capacity initially on the basis of their "prevailing" bookings of NTS Exit Capacity. Where users make a sufficient commitment via the UNC process or an ARCA, National Grid would allocate additional flat capacity in annual blocks, without limit, for years beyond investment lead times. In shorter timescales, further capacity release programmes, constrained by the level of actual capacity, would operate through "pay as bid" auctions, first of annual capacity and later of daily capacity. The level of actual capacity (yet to be determined) would define the minimum "baseline" levels that National Grid had to release.

National Grid would cease to offer long-term interruptible NTS Exit Capacity and would only offer it on a day-ahead basis. Shippers wanting to secure long-term interruptible Exit Capacity would have to book "firm" flat capacity or buy interruptible capacity from another shipper. National Grid would also hold tenders to buy-back capacity in certain conditions (e.g. when the physical network was unable to deliver the anticipated gas flow). National Grid would facilitate capacity trading to enable shippers to transfer or assign capacity to other users at the same Exit Point.

Shippers would be exposed to overrun penalties only when total flows exceeded aggregate capacity holdings at an exit point, a rule intended to provide some protection against capacity hoarding. In effect, unused capacity held at an exit point would automatically be available to other users at no cost, as long as the total capacity held at the point exceeded demand for it.

B.3.2. Questions

1. What **benefits** would you expect to derive from moving from the transitional arrangements to those envisaged by Modification 116C? Please quantify where possible.
2. What are the likely **one-off costs** (e.g. IT costs, staff recruitment or training costs etc) you would incur, as a result of moving from the transitional arrangements to the flat capacity arrangements envisaged by Modification 116C?
3. What are the likely **ongoing costs** (e.g. transaction, risk management or accounting costs etc) you would incur, as a result of moving from the transitional arrangements to the flat capacity arrangements envisaged by Modification 116C?
4. Apart from any additional costs you may incur, do you foresee **any other disadvantages** of moving from the transitional arrangements to the flat capacity arrangements envisaged by Modification 116C, such as operational difficulties for your business or others?
5. Do you anticipate participating in (a) the **longer term auctions of flat capacity**, envisaged under Modification 116C and/or (b) the **flat capacity buy-back** arrangements?

B.4. Introducing Flat and Flexibility Capacity (Modification 116)

B.4.1. The Flexibility Capacity Product

Modification 116 suggests the introduction of both the flat and flexibility capacity products. The flat capacity product is the same as described above, for Modification 116C. The nature of the flexibility capacity product envisaged by Modification 116 is summarised below.

National Grid does not consider it efficient to invest in providing flexibility capacity on the NTS, so this process is not intended to provide investment signals. Instead, National Grid expects the limit on flexibility capacity to encourage users to ration more efficiently their use of the flexibility provided by linepack and system operations, i.e. to manage more efficiently their within-day gas offtake profiles. The volume of service required by a user is defined, as under the transitional arrangements for DNs, as (1) the cumulative quantity taken in the sixteen-hour period from 06:00 to 22:00 *less* (2) sixteen times the average hourly quantity for the gas day (06:00-06:00). The second of these amounts represents the quantity of gas that the shipper would have taken over the period from 06:00 to 22:00, if the daily quantity of gas had been taken at a constant rate throughout the day.

It is envisaged that the release, transfer and assignment of long-term flexibility capacity will be constrained by zonal, regional and national maxima. The release of shorter-term flexibility capacity will be limited to what is available, as with flat capacity. Likewise, National Grid will facilitate trading and will hold tenders to buy-back flexibility capacity as required for capacity management purposes.

Special rules would apply at bi-directional points, such as storage and interconnectors, to classify the point on a particular day as *either* entry *or* exit, based on measured aggregate gas flows. At multi-user exit points, appointed agents would need to allocate within-day gas flows to individual users, to determine their use of flexibility capacity.

B.4.2. Questions

1. What **benefits** would you expect to derive from the introduction of both the flat and flexibility products as outlined in Modification 116, *when compared with the transitional arrangements*? Please quantify where possible in the attached spreadsheet.
2. What are the likely **one-off costs** (e.g. IT costs, staff recruitment or training costs, etc) you would incur as a result of the introduction of both the flat and flexibility products as outlined in Modification 116, *when compared to the transitional arrangements*?
3. What are the likely **ongoing costs** (e.g. transaction, risk management or accounting costs etc) you would incur from the introduction of both the flat and flexibility products as outlined in Modification 116, *when compared to the transitional arrangements*?
4. Apart from any additional costs you may incur, do you foresee **any other disadvantages** (such as operational difficulties) from the introduction of the flexibility capacity product proposed in Modification 116, *relative to Modification 116C, which only introduces the flat capacity product*?

B.5. Refining Flat and Flexibility Capacity (Modification 116B)

B.5.1. Refinements Prescribed by Modification 116B

Like Modification 116, Modification 116B proposes the introduction of flat and flexibility capacity. However, it makes certain refinements to the nature of the products. The key differences between Modification 116 and Modification 116B are as follows:

§ When estimating a user's consumption of flexibility capacity, Modification 116B increases the tolerance of cumulative daily flow from 1.5% to 3%

§ New NTS supply points and CSEPs commissioned between 01/07/2007 and the start of the enduring arrangements would secure initial "prevailing" NTS flat exit capacity based on the NTS exit capacity that they had registered.

§ Modification 116B distinguishes between release of incremental flat capacity and of flat capacity made available at existing exit points. to slacken constraints imposed by the timetable for investment, effectively by allowing applications outside the July window and for start dates other than 1 October.

§ Under Modification 116B, there would be no flexible product commodity charge, but only an overrun charge, which would be triggered where (1) National Grid announces a "flexible constrained day" and (2), within a zone, where use of flexibility exceeds aggregate daily holdings.

§ If a user's flexibility utilisation increases as a result of an intertrip or forced outage, the overrun calculation will be based on that user's prevailing Individual Offtake Profile Notice (OPN) at the time the intertrip or forced outage commenced (rather than measured offtake).

The proposal also outlines requirements on National Grid to publish details of flexibility utilisation, overrun quantity and charges and expected flexibility utilisation.

B.5.2. Questions

1. What **difference in benefits** would you expect to derive from the adoption of Modification 116B *rather than Modification 116*? Please quantify where possible in the attached spreadsheet.
2. What are the likely differences in **one-off costs** (e.g. IT costs, staff recruitment or training costs etc) you would incur from the adoption of Modification 116B *rather than Modification 116*?
3. What are the likely differences in **ongoing costs** (e.g. transaction, risk management or accounting costs etc) you would incur from the adoption of Modification 116B *rather than Modification 116*?
4. Apart from any effect on costs you may incur, do you foresee that Modification 116B would mitigate any of the **disadvantages** due to the introduction of flat capacity *as per Modification 116C* (which you identified under question 4 in section B.3.2) or due to the introduction of flexibility capacity *as per Modification 116* (which you identified under question 4 in section B.4.2)?

B.6. The Entry Capacity Regime

B.6.1. Background

Some aspects of the “enduring arrangements” proposals for the exit regime mirror arrangements for NTS entry capacity, which in summary involve the following:

§ Auctions of long term capacity entitlements, intended to aid investment decisions;

§ Auctions of medium- and short-term firm and interruptible capacity;

§ Redistribution (or recovery) of auction revenues that are in excess of (or less than) the regulated cost recovery targets via adjustments to commodity charges;

§ Buy-back arrangements by which National Grid may repurchase capacity via forward and option contracts or on-the-day mechanisms; and

§ Incentives designed to encourage National Grid to maximise the availability of capacity whilst efficiently managing the costs of constraints.

This regime replaced a previous scheme by which (1) entry capacity was made available on demand at administered prices, and (2) any constraints arising were dealt with by scaling back capacity pro rata.

B.6.2. Questions

Please answer the following questions in relation to your experience of the implementation and operation of this entry capacity regime.

1. Does the current entry regime provide **clear investment signals**? Please illustrate your answer with examples where applicable.
2. Aside from the impact on investment signals, what **other benefits** have the current entry capacity arrangements achieved compared to the previous scheme?
3. What were the **one-off costs** to you of implementing the current entry capacity regime, including costs of changing IT, recruitment or training, following the removal of the previous scheme?
4. What are the differences in your **ongoing costs** (e.g. transaction costs, risk management, accounting etc) of operating the current regime compared to those under the previous scheme?
5. Other than costs of operation, what **disadvantages** has the regime entailed, including any impacts unforeseen at the time of implementation?

B.7. General Comments

B.7.1. Other Problems, Benefits, Methods

We would like to offer you an opportunity to comment generally on the proposed reforms.

1. Are there any **general problems or benefits** related to the proposed reform of the NTS offtake arrangements which have not been covered by the preceding questions?
2. If you consider reform of the NTS offtake arrangements necessary, do you think the appropriate changes could be made through **simpler means**? Please give details.

B.7.2. Overall Assessment

This document has outlined four suggested approaches to modifying the UNC to reform NTS offtake arrangements. Please indicate which of the following statements represents your view:

1. Modifications 0116, 0116B are addressing real problems with the transitional arrangements in an efficient manner.
2. There are real problems with the transitional arrangements, but Modification 0116C addresses them adequately, without the need to introduce flexibility capacity.
3. There are real problems with the transitional arrangements, but Modifications 116, 116B and 116C do not address them as efficiently as other possible solutions.
4. There are no real problems with extending the existing arrangements, as proposed by Modification 116A.

Please select one of the four options above and add any comments that would illustrate the reasons for your answer.

B.7.3. Problems to be Solved

If you gave one of answers 1 to 3, what problems do you think the modifications are trying to address? Please select one or more of the following:

1. Changing the current arrangements as proposed will not address any real problems.
2. There is a need for better coordination of investments between the NTS and DNs.
3. NATIONAL GRID needs longer term signals of demand, for more efficient planning of its investment.
4. The arrangements must encourage TCCs to reduce (or at least not to increase) their use of flexibility, by encouraging a flatter profile of gas flows within each day.
5. Different treatment of different classes of user is discriminatory and cannot be allowed to persist.
6. Other (please specify).

B.7.4. Other Possible Methods

Given the problems you have identified, do you think there is a better alternative solution among the following list (select one or more)?

1. Define all users' requirements to hold exit capacity by reference to their peak usage over a period shorter than a day, e.g. 24 times average usage over the period 06:00-22:00, or 24 times usage in the peak hour (=24 x Standard Hourly Quantity).
2. Apply the zonal, regional and national maxima to flat capacity (and not introduce flexibility capacity).
3. Have Ofgem audit the detailed investment choices made by DNs and National Grid as part of a price control process.
4. Place limits on TCCs' use of flexibility (and other aspects of their offtake profiles) via ARCAs, NExAs, SCAs.
5. Other (please specify).

Appendix C. List of Respondents

- **Shippers**
  - Centrica
  - E.ON
  - RWE
  - International Power
  - Total
  - Statoil
  - EDF
  - SSE
- **Storage Operators**
  - Centrica Storage
  - SSE
  - E.ON (future storage operator)
- **DNOs**
  - One anonymous GDN
- **TCCs**
  - Two anonymous industrial TCCs
- **Irish gas market players**
  - Bord Gáis Networks
  - Bord Gáis Eireann
  - ESB

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