National Grid Transco

Winter Operations Report – 2003/2004

Introduction

This report provides a review of the 2002/3 winter and an overview of the coming winter, covering both electricity and gas transmission systems. It also addresses specific questions raised by Ofgem.

We have addressed our primary duty to provide adequate gas and electricity transportation capacity and fulfil our role as residual balancer of both networks. We can confirm that we are able to meet our various obligations. Although NGT is not responsible for ensuring sufficient supplies are available to meet a given security standard, a considerable part of the report addresses our analyses of wider supply security in the forthcoming winter period.

The report benefits from recent analyses that have been undertaken by NGT to model the potential effects of a range of winter conditions across both energy transmission networks. These analyses are more informative than previously available and reflect the opportunity to share projected scenarios between NGC and Transco showing the benefit following our merger, of increased understanding about common assumptions and regime interactions.

The analyses reflect the latest information available to NGT from the gas industry on beach availability, storage and interconnector capabilities, and enable us to model potential outcomes. As with all scenario modelling the results are subject to interpretation and NGT will continue to discuss its observations with Ofgem and other industry participants.

The level of security of supply that can be assessed in both gas and electricity is dependent upon many variables, some of which are available as forecasts to / from market participants and others which have to be deduced. The major deductions in this report relate to the reliability of beach supplies and the probability of interruption of gas fuelled generation during a cold winter. We have also taken account of some indications that the use of gas storage and interruptible contracts by Shippers may be changing. In response to a request from Ofgem over the summer we gathered information on mothballed generation and the ability of CCGTs to switch to back-up fuels. This has substantially clarified the situation.

The operation of the electricity transmission network is fulfilled under the National Grid Company Electricity Transmission licence and the gas transmission network under the Transco Gas Transporter licence.

For the purpose of this report "NGT" is used to cover both licensed entities, whereas in practice, our activities and the sharing of information is governed by the respective licences.

The report is presented in three sections. Section A contains a review of the winter 2002/2003 outturn. Section B presents an over-view of this coming winter. In Section C we consider electricity / gas interaction. A schematic of participant interfaces and an explanation of key technical terms are given in the appendices.

Summary

The main conclusions of this report are:

- The Transco and National Grid networks have the capacity to meet the published transportation requirements of cold winters.
- In evaluating security of supply for gas this coming winter, it is necessary to consider the level of demand (which is highly influenced by weather), the availability of beach gas, the role of the interconnector, potential market response and the use of storage. Different assumptions will deliver a wide range of potential outcomes and NGT offers a range of assessments.
- At the start of the winter there is sufficient gas forecast to be available at the beach, through the interconnector from Belgium and in storage to meet 1 in 50 severe winter demands.
- However 1 in 50 severe winter security can only be achieved if we experience necessary combinations of high beach delivery levels with limited use of storage gas to support interruptible demand and for export to Europe. The delivery of beach gas is critical and will be dependent on both the extent of any offshore unreliability and commercial influences.
- In recent years the forecast beach deliveries notified to NGT have not been achieved, even though we have experienced record demand days. NGT has reported on this in recent years and there are differing views about the level achievable in a severe winter. Our operational experience suggests it will probably be less than 100%. To test the sensitivity to supply security we have therefore modelled the effects of a potential shortfall in actual beach deliveries (say 95% availability) compared with forecast expectations, together with the potential use of storage to supply interruptible demands (based on experience of earlier winters). This analysis suggests that with the top-up mechanism as currently applied severe winter security could be significantly less than 1 in 50. In the report we propose methods to improve the top-up mechanism to mitigate this risk.
- In evaluating security of supply for electricity this coming winter it is again necessary to consider the level of demand (which is also highly weather related), the availability of generation, European market effects on the direction of flow of the French

interconnector, and levels of gas interruption and availability of alternative fuels at CCGT stations. Different assumptions again deliver a wide range of potential outcomes and therefore NGT has sought to offer a range of assessments.

- Throughout this year we have highlighted to the market the tightening position of electricity generation and demand. As a result some plant which had been mothballed is in the process of being returned, demonstrating a positive market response. Based on current projections the surplus of electricity generation above forecast average peak winter demands is 6.0GW. This assumes that both the Scottish and French interconnectors are importing at their maximums and that there is no loss of generation from interruption of CCGT's.
- From the most recent information we have been given by the generating companies, there is around 2.6GW of mothballed plant with the physical potential to be returned before or during this winter. However their advice is that only 0.8GW of this is likely to be returnable in practice due to the challenges involved. The remaining 1.8GW is highly speculative. If the 0.8GW were returned the surplus over average winter demand forecast would then increase to 6.8GW.
- However this level of surplus could be eroded by a number of factors. Firstly demand in cold weather will be greater. For planning purposes we calculate average cold conditions as a level of demand that has a 50% probability of occurring within any winter. On this basis the demand will be 2.2 GW higher than average. This would reduce the potential surplus to between 3.8 and 4.6GW.
- During the winter, it is possible that the interconnectors will not be at maximum import. This will depend on the market conditions and generation availability prevailing at the time in Scotland and France. It might be prudent to assume that the total import is reduced to 3GW total, reducing the surplus to between 2.6 and 3.4GW.
- Under prolonged cold conditions it might also be expected that some or all CCGT generation will be interrupted. If conditions in the gas market determined that all interruptible CCGTs were interrupted this would reduce the available generation by 8.6GW. However 5.9GW of interruptible CCGTs can generate on alternative fuels so that full interruption would result in a net loss of around 2.7 GW. Under these circumstances the surplus would reduce to between a deficit of 0.1GW and a surplus of 0.7GW.

Each of the above scenarios would have to occur to represent the "worst case" risk to electricity security of supply. i.e. limited further return of mothballed plant, long cold winter, restricted beach gas and interruptions, reduced electricity imports and failures of CCGTs to change over to alternative fuels (and / or limited alternative fuel stocks). An unusual level of plant failure in real-time (as occurred on the 10 December 2002) would exacerbate the problem in maintaining electricity supplies without voltage and demand reductions. While each of these scenarios is credible, there is a low probability of them all occurring concurrently.

Under most scenarios network security can be maintained without any interruption of firm gas supplies or electricity demand, although voltage reduction (which we would not expect to be discernible to customers) may be required to cover any significant generator failure if the most onerous conditions occur together. Therefore, we are suggesting a number of changes to existing arrangements to provide an added level of security in such “worst case” scenarios.

NGT remains strongly committed to supporting market processes that will facilitate an appropriate level of energy security. To this end we believe the level of gas and electricity supply security would be enhanced if the following market changes were to be introduced:

1. NGT’s proposals to strengthen the Electricity Market Imbalance Price. This would introduce marginal pricing for System Buy Price (SBP) at times of demand reduction, and in the longer term at all times. This should encourage the further return of mothballed generation and encourage increased availability of generation and interconnector imports at critical times.
2. The proposed new Maximum Generation Service for this winter. This would give NGT access to ‘reasonable endeavours’ generating capability of the order of a further 0.6GW in addition to that assumed available in the above summary. We are also intending to issue an open market tender for short-term reserve this coming winter. Any additional reserve contracted as a result of this tender process will be based on an economic assessment of the offers compared to the forecast costs of procuring short term reserve in the balancing mechanism. We will also consider within this process procuring reserve to provide greater certainty of our short-term reserve requirements being met.
3. The level of gas security provided by top-up was increased, by adjusting the monitor level to reflect more realistic beach availability assumptions. This would have the effect of preserving gas in storage during the earlier parts of the winter in order to support generation and other needs if the weather deteriorated to cold conditions. If the monitor level is adjusted it could create substantial costs and therefore we believe the Network Code should be modified in a way similar to that proposed by NGT before, to enable the market to be fully exposed to these costs and hence facilitate a market response. It would also be beneficial to strengthen the counter nomination process to generate a more reliable physical outcome.
4. Shipper Nominations were made firmer (e.g. by a supplementary scheduling charge based upon the nomination prevailing at the start of the gas day).
5. A new process was introduced that enabled trading of interruptible rights, allowing shippers to substitute interruption sites with other shippers and hence on occasions when the electricity market is tight enable some market priority to be given to sustaining gas fuelled generation.

6. A new service was developed which enabled interruption of gas to CCGT's (by both shippers and NGT) to be effectively relieved over the electricity peak demand hours.
7. NGT were enabled to interrupt interruptible gas supplies for winter security reserve purposes having established new trigger thresholds. In addition, consideration should be given to improving the incentives on market participants in relation to Transco interruption for Supply-Demand purposes, so that they are incentivised to balance themselves rather than relying on our actions.

However we remain concerned that there may be circumstances in which security of supply cannot be maintained by market mechanisms alone. It will be important for the purposes of maintaining the integrity of the networks that clarity of appropriate action is established in anticipation of these extreme circumstances. We therefore also believe that security would be enhanced with the introduction of other <u>backstop</u> mechanisms:

8. Enabling the gas system operator to temporarily direct the restoration of gas delivery to interrupted CCGTs over the peak electricity demand periods, where market mechanisms had not already achieved this, and where it had been established that it would avoid an electricity supply shortage.
9. Enabling the gas system operator to take the situation on the electricity network into account when taking gas balancing actions (e.g. interruption decisions or the acceptance of OCM Offers), if it was necessary to maintain electricity supply security.

The potential benefit of the electricity and gas system operators co-ordinating actions in an emergency to further promote the security of supply was identified in the 2002/2003 Winter Operations report and is under discussion with the DTI and Ofgem.

NGT is very supportive of the Ofgem/DTI initiatives already underway following the summer interruption events of 17/18 June 2003 to improve the data provision from upstream parties. It would also be beneficial if there was greater certainty that interruptible CCGTs would be able to reliably generate on alternative fuels for prolonged periods. In the longer term, we believe there is merit in CCGTs with firm gas supplies also being required to have alternative fuel capability for fuel security reasons.

In addition it would be helpful if NGT's understanding of developments of Shipper/Supplier interruptible contracts could be confirmed, in order to validate this element of the analysis of winter security.

SECTION A - Experience of 2002/2003

Gas Demand

UK daily gas supply reached a new record level of 4,940 GWh (452 mcm) on 8th January 2003 which represents 85% of the forecast 1 in 20 peak day of 5,810 GWh (531 mcm). Gas demand from the NTS peaked on 7th January 2003 at 4,910 GWh (449 mcm).

Overall the 2002/2003 winter was ‘1 in 10 warm’ and was the seventh warmest winter on record.

Transco interrupted demand on the 8 January 2003 in the South West, (which coincided with the record daily demand on the electricity system), and on the 9 January 2003 in the South East and South West. Both of these were required to resolve transportation constraints. This included the interruption of a number of gas-fired power stations. The communication process between Transco and National Grid was effective and there was no disruption to electricity supply.

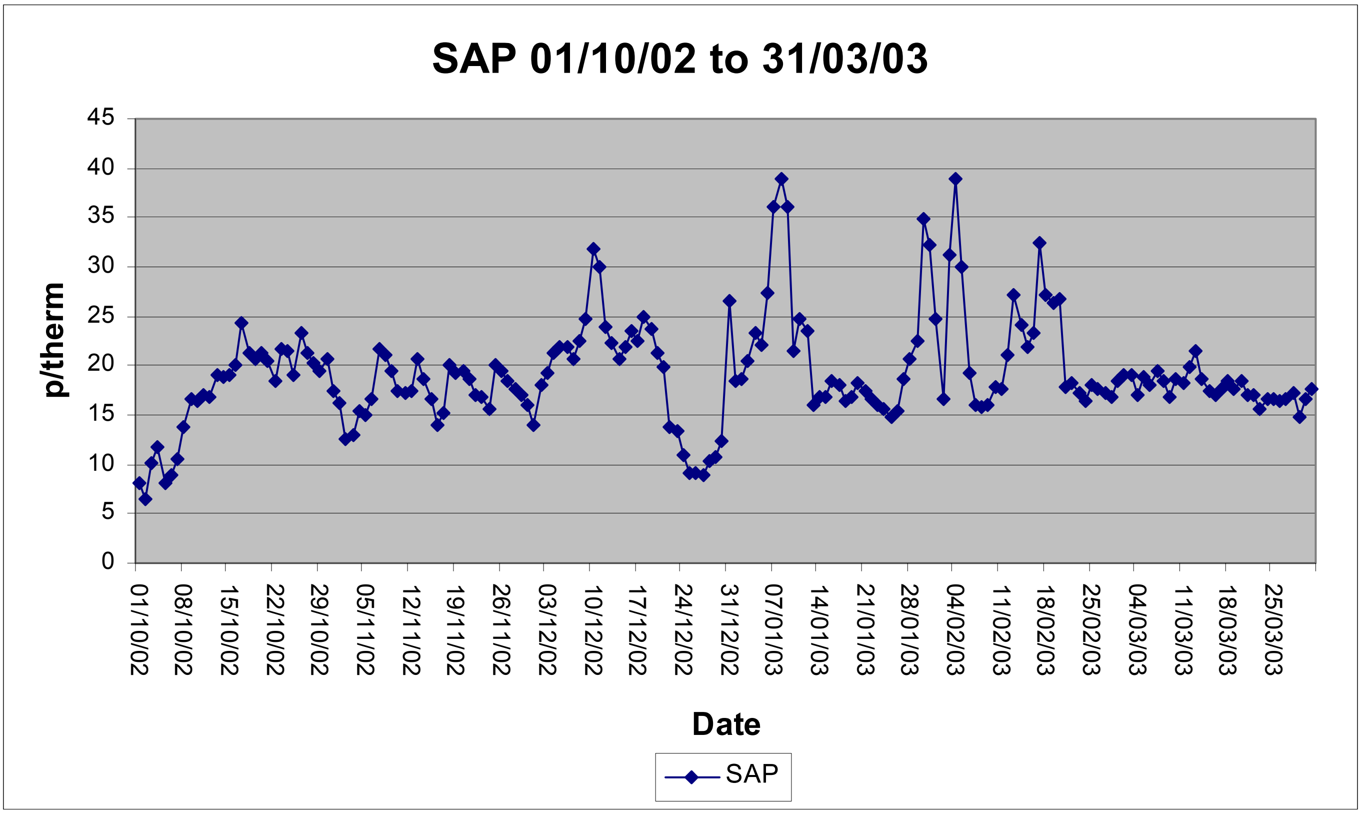
Gas Prices

Generally the System Average Price (SAP) price was between 15p/th and 20p/th, over the period October 2002-March 2003.

On 8 January 2003 SAP was 39.00 p/th, which was the record supply day when Transco needed to buy gas to balance the system under difficult supply/demand conditions.

On 30 January 2003 SAP was 34.78 p/th, which again was a high demand day at 434mcm. Shippers were trading at high prices and a sub-terminal supply loss of 6mcm prompted Transco buy actions.

On 4 February 2003 SAP was 38.98p/th. There were supply shortages the previous day and a within sub-terminal supply loss which prompted Transco buy actions. Shippers were also trading at high prices.



Gas Prices Over Winter 2002/2003

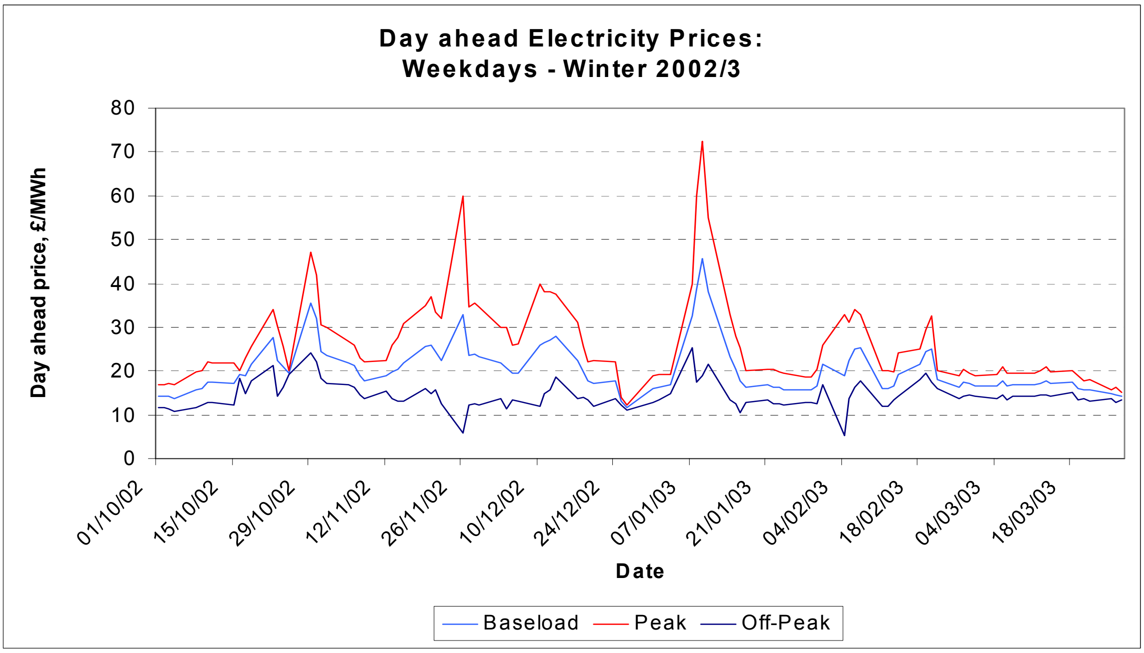
Electricity Demand

Electricity demand reached a new record high on Tuesday 10 December 2002 of 54,430MW for the half-hour ending 17.30hrs (after 235 MW of Notified Customer Demand Management).

Strong easterly winds and very cold spot temperatures in the week beginning the 9 December combined to make the weather close to Average Cold Spell (ACS) conditions for a few days.

The record demand of 54.8GW (including approx. 0.4GW of station demand) was met for the peak half hour ending 17:30 on 10 December 2002. The notified total real-time availability of generation (MEL) at this time was 56.4GW of which approx. 0.7GW was unavailable because its notice period was too long for it to be called in the Balancing Mechanism. This meant that 55.7GW of generation was available to us to meet demand and provide a surplus for operating reserve.

Electricity Prices



Average Electricity Prices Winter 2002/2003

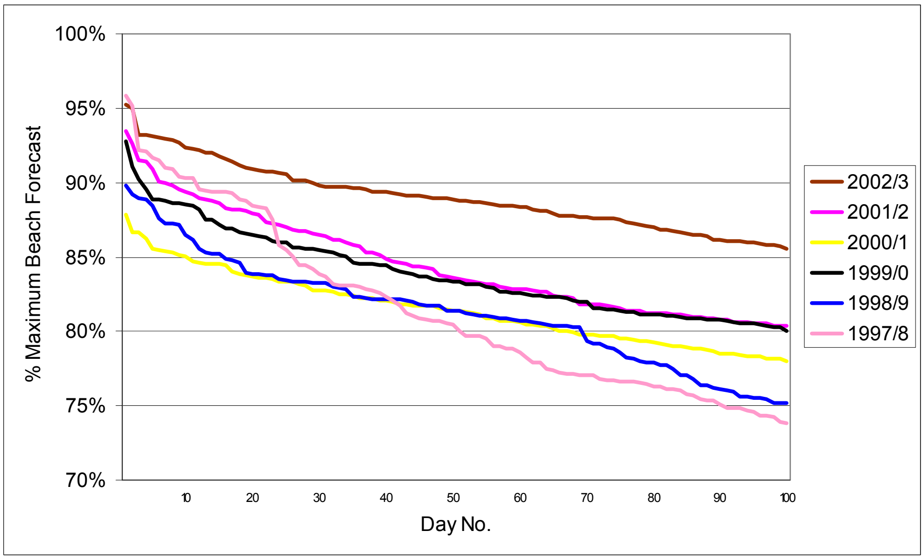
Day-ahead base load electricity prices rose from £14/MWh at the beginning of October to between £20/MWh and £30/MWh by mid-December. They then jumped to over £45/MWh at the beginning of January during the first week after the Christmas holiday period.

Following the jump to £45/MWh at the beginning of January prices quickly fell to between £15/MWh and £25/MWh. Prices then continued a downward slide to around £14/MWh by the end of March. Peak load prices have followed the same pattern, reaching a maximum of over £70/MWh on 9 January 2003.

Section B – Gas overview for winter 2003/04

Gas Supply

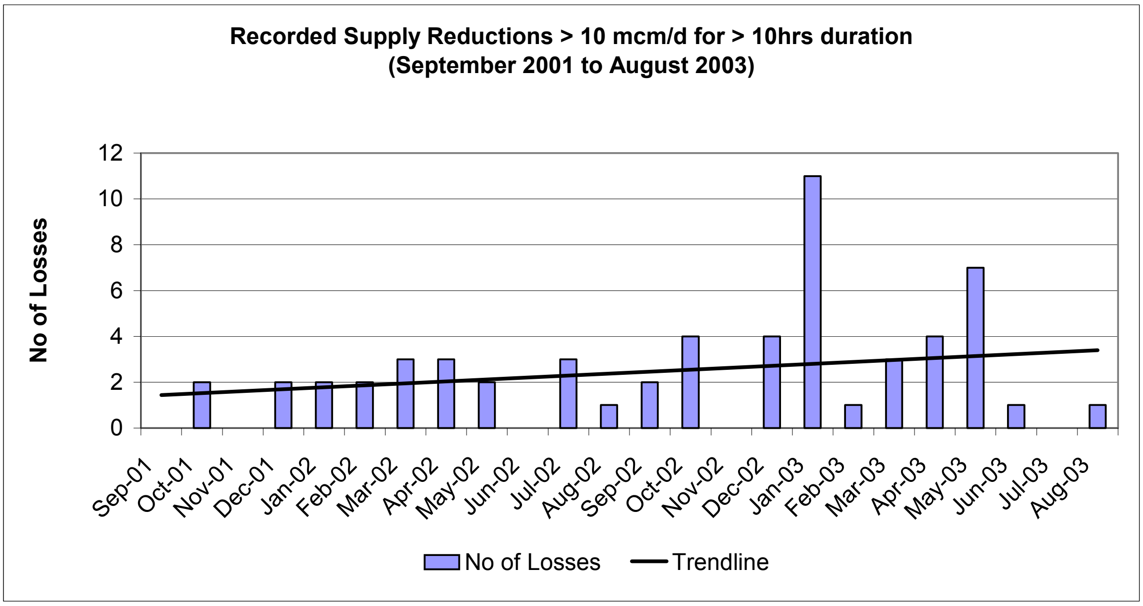
Analysis of recent years experience (see chart below) shows that the maximum beach supplies delivered during the winter period have fallen well short of the maximum beach forecast. Typically levels of 90 – 95% of maximum forecast have been achieved with the supply/demand match being achieved by substantial use of storage and occasionally by depletion of linepack.



For 2002/03 the maximum beach gas delivered on a day was 368mcm however this did not coincide with the maximum demand or supply day. On the 8 January when the winter's maximum supply occurred the beach delivery was only 360mcm (93% of forecast) despite the total supply actually reaching 452mcm.

Based on this experience we no longer believe it realistic to continue to assume 100% of maximum beach forecasts will be delivered, particularly recognizing that the UK Continental Shelf infrastructure is reaching the latter stages of its working life. Others have supported our views.

This deduction is supported by examination of our records (see below), which demonstrate a significantly rising trend (90% year on year increase) in 'on the day', sustained terminal flow reductions compared with nominated levels. In addition over the critical winter months of Dec – Feb the year on year rise was from 6 instances to 16 (167% year on year increase).



We have therefore modelled the effects of a potential shortfall in actual beach deliveries (say 95% availability) compared with forecast expectations, together with the potential use of storage to supply some interruptible demands (based on experience of recent winters). The analysis suggests that with the top-up mechanism as currently applied severe winter security could be significantly less than 1 in 50.

The effects of beach delivery levels and reliability will become more critical with the tightening of the supply/demand match over the next few years until new offshore gas infrastructure is built. Later in the report we suggest how the role of top-up might mitigate some of this risk.

The recent, and unprecedented summer interruption events of the 17/18 June 2003 have also heightened our view that the industry must develop more robust arrangements for the exchange of operational information from upstream parties, interconnectors and storage operators to the system operator. NGT is supportive of the DTI / OFGEM initiative to improve these data flows for the forthcoming winter, and has recently identified and discussed its specific data requirements with the United Kingdom Offshore Operators Association.

Gas Demand

Interruption for Supply/Demand Balancing

In a severe winter, interruption would be necessary to balance supply and demand. NGT can only interrupt when demands are above 85% of a 1 in 20 peak day other than to manage transmission constraints. We would do this so far as operationally possible in an equitable manner across shippers, and between large loads directly connected to the NTS and LDZ demand sites. We determine the volume of interruption by assessing supply/demand imbalance on the day in the affected area and our timing of such interruption is driven by events on the day and the notice periods required. Restoration takes place as soon as operationally safe and practicable to do so.

In the absence of shipper (commercial) interruption and assuming full use and availability of beach gas, we can give an indication of the level of interruption that may be required in order to cover shipper imbalances and NTS transmission constraints.

We have modelled a number of different weather patterns based on actual weather over the last 75 years, and assuming 100% maximum beach supplies is delivered.

Under the range of cold winter conditions analysed, interruption of CCGT load would be required on between 20 and 36 days. Actual interruption requirements in 2003/04 will depend upon shipper behaviour (e.g. use of storage), beach gas availability, interconnector flows, the severity of the winter weather and operating conditions on the network. However it is clear that even in a 1:10 cold winter many days of interruption can be expected and the colder the winter the more prolonged that interruption will last.

Interruption for NTS Gas Transmission Constraints

For Winter 2003/2004 there are three potential NTS transmission constraints at Aylesbury (Feeder 7), Wormington (Feeder 14) and Chelmsford (Feeder 5), compressors potentially affecting supplies to the South West and South East.

The constraint process is triggered when the flow through the compressor reaches, or is expected to reach, its maximum. Partial or complete interruption of downstream power generation and Network sites may then be invoked and when this is exhausted, constrained LNG is utilised.

Interruption would be necessary to overcome the constraints in a cold winter and this could affect 4 NTS interruptible CCGTs for up to 38 days depending on the severity of the winter.

Maximum Interruption Volumes (MCM/d)

Constraint	NTS Offtakes	LDZ Exit Zones
Feeder 7	10.16	8.24
Feeder 5	4.12	12.5
Feeder 14	1.51	0.59

Power Generation Gas Demand

The maximum contractual power generation gas demand from the National Transmission System (NTS) for the 2003/04 winter is shown in the following table:

2003/04 MCM/d	Firm	Interruptible	Total	No. of CCGTs
NTS connected	75	49	124	35
LDZ connected	3	3	6	4
Total	78	52	130	39

NTS (& LDZ VLDMC) Power Generation Demand 2003/2004

For 2003/2004 there are 35 large (>1 mcm/d) power generation sites connected to the NTS and 4 connected to LDZ transmission systems. In addition there are a number of smaller embedded power generators connected to downstream LDZ systems.

The maximum large firm power generation demand for winter 2003/2004 is 78mcm/d, which represents 14.5% of peak day gas demand. On all days in a 1 in 50 cold winter, other than the peak day, we assume a maximum power generation demand of 73% of the maximum CCGT contracted demand. This is because some CCGTs move on to part-loaded mode (taken across a gas day) outside of the electricity peak demand periods.

Gas security has two dimensions; (a) deliverability throughout the winter period and (b) gas availability to enable the supply of loads across the winter (especially storage).

Based on 100% availability of forecast beach gas, we believe there would be sufficient available deliverability from supply sources (beach, European Interconnector and storage) to support 100% of firm power generation demand on the 1 in 20 peak day. We also believe that provided shippers do not excessively supply interruptible load from storage that there will be sufficient gas in store to sustain firm power generation daily offtake. The maximum interruptible NTS (& LDZ VLDMC) power generation demand for 2003/4 is 562 GWh/d (52 mcm/d).

There is insufficient UK supply deliverability to support all interruptible gas demand on the 1 in 20 peak day and insufficient UK storage capacity to sustain all interruptible gas demand for the full duration of a 1 in 50 winter.

Use of storage and interruption

As the gas market has developed so the use of storage facilities has been transformed. They are now an integral part of the way shippers manage their day to day balance, rather than being solely used to manage seasonal variations. Reflecting this change, we have experienced storage being used in export mode in recent winters whilst on the same days gas has been supplied to interruptible loads and to Europe via the interconnector.

Furthermore, during the year we have been advised that many shippers are now entering into "NGT only interruption" contracts with consumers. This implies that storage might be used more aggressively both during the run into a cold winter and even once cold weather has become established. Our analysis suggests that the combination of these market developments can be expected to have a material effect on energy security and hence the requirement for top-up actions

Role of Top-Up

NGT's role in relation to top up storage is defined in Section P of the Network Code whereby NGT seeks to ensure that the industry in aggregate holds a minimum stock in storage sufficient to satisfy demands up to 1 in 50 severe demand conditions.

As indicated above, recent analysis suggests that previous assumptions (in particular regarding beach gas availability and use of storage) may be too optimistic. If beach gas availability in a severe winter was to be below 100% of the maximum forecast, and storage gas is used more extensively to supply interruptible load, sufficient stocks of gas may not be available to meet all firm demand.

This analysis reflects advice received during 2003 that many shipper interruption contracts have moved progressively to "NGT only interruption". The modelling assumes that NGT would only interrupt in order to manage transportation constraints and for supply/demand purposes when failure to supply would otherwise occur.

NGT will be refining its modelling over the coming weeks and will continue to discuss potential mitigating factors with Ofgem. The level of security provided by top-up could be increased, by adjusting the monitor level to reflect more realistic beach availability assumptions. If the monitor level is adjusted it could create substantial costs. We therefore remain of the view that the Network Code should be modified to enable the market to be exposed to the potential costs of the top-up process, thereby encouraging a market response much earlier in the winter. It would also be beneficial to strengthen the counter nomination process to generate a more reliable outcome.

In addition, we believe it would also enhance security of supply if NGT were enabled to interrupt interruptible gas supplies for winter security reserve purposes having established new trigger thresholds (e.g. to allow interruption at demands lower than 85% of peak levels). Consideration should also be given to improving the incentives on market participants in relation to Transco interruption for Supply-Demand purposes, so that they are incentivised to balance themselves rather than relying on our actions (as the growing use of ‘NGT only’ interruption contracts would seem to suggest).

Gas security and demand side response

Taking a view that beach gas availability over a long run of cold weather will be at say 95% of the forecast maximum, and that storage will be used by shippers to a pattern experienced in earlier winters with some early depletion, the level of security will be significantly below 1:50. Under these circumstances it might be expected that there would be some demand side response. However independent research and analysis has revealed that this is likely to be limited, and mostly offered through arbitrage at gas fired power generation. Our gas demand forecasts already include diversity factors, which recognise that not all CCGTs will be generating at full rate throughout. In severe winter scenario planning a material level of further response can be discounted, as this generation will be key to achieving a power balance.

Aside from the CCGT sector, our research has demonstrated that very few consumers are directly exposed to the spot gas price. Without a direct incentive, demand-side responses will rely on new arrangements between shipper/supplier and consumer. However, recent experience of supply shocks has also revealed that the response from the industry to unanticipated effects requires a reasonably long lead-time. It is not always immediately apparent what steps might be taken by those involved to manage changed circumstances and establish new arrangements to match the challenge or opportunity. We do not therefore believe that it is prudent for us to assume that the market would respond in a timely way or with sufficient scale to enhance the overall security of energy supply with demand side response in the immediate circumstances. However the experience of a supply deficit might be expected to generate appropriate action for the following winter. Clearly any enhanced demand side response from that we have assumed would provide additional security of supply benefits.

Section B – Electricity overview for winter 2003/04

Electricity Demand levels for 2003/2004

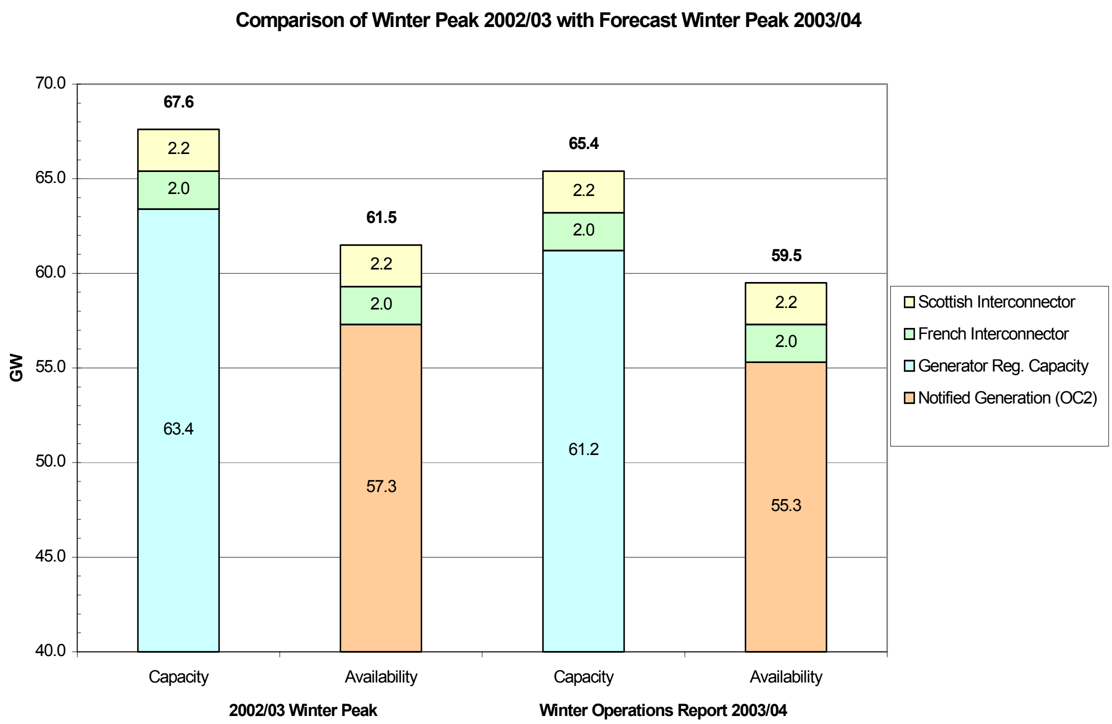
The predicted cold winter peak electricity demand for the coming winter is 55.7GW (and 53.5GW normal demand) compared with a cold winter corrected outturn of 54.6GW for 2002/2003, giving a year on year growth of 1.1GW.

The actual maximum metered demand during winter 2002/2003, as discussed above, was 54.4GW and hence was extremely close to the cold winter peak demand prediction.

Notified Generation Availability

The level of available power generation has decreased since winter 2002/2003 with significant amounts of generation being mothballed. Currently notified generation availability is approximately 55 - 56 GW over the peak-demand weeks for 2003/04. In addition electricity may be imported from Scotland and France.

The graph below compares our experience of 2002/03 with the forecast for 2003/04.



The capacity figures represent the registered availability of the generators, whereas the availability figures represents the generators view of the likely real capability, taking account of a number of factors. These include an implicit allowance for breakdowns, as discussed below, as well as planned outages (which includes a reduction in generating unit output or a complete unit / station outage). The 2003/04 figures are based on generator submissions for week 3 under OC2 as at 19th September 2003.

The generation available shown on this graph is that declared by the Generators under the Grid Code Operating Code OC2, in which the Generators are required to submit their own estimate of output usable taking in to account the statistical likelihood of breakdowns for timescales greater than eight weeks ahead. NGT does not include any other breakdown allowances in these timescales for calculating margins / surpluses. This typically reduces generation available by around 8% when compared to the total Registered Capacity of the generation available. In timescales of less than eight weeks ahead Generators are not required to include breakdown allowances and NGT includes additional margin to cover for generation breakdown calculated from actual historical generator shortfall.

In this graph it can be seen that the difference between capacity and availability over the winter 2002/03 peak is similar to the data notified by the generating companies for this coming winter.

The generator availability data is that currently declared by the generating companies and does not reflect the potential for more mothballed plant to be returned (it is therefore not the same as installed capacity indicated in the Seven Year Statement).

Generation Market Reporting

This data is usually combined with our latest forecast for normalised winter demand and the required surplus to give an operating margin, which is published for market participants on the internet at www.bmreports. Since the spring of this year this information has been indicating an insufficient surplus for this coming winter.

This situation has been highlighted by NGT at the electricity industry forums and in briefings to JESS and Ofgem. We have sought to ensure that all market participants were aware of the forecast low levels of surplus for this coming winter. This has resulted in a market response and more recently the announcement of some mothballed generation being returned. This data has been of particular value to the industry over the last year. In addition we have provided analyses of information on the potential impact on the security of supply in the event of the complete loss of availability from specific generating companies for DTI and Ofgem.

Recently we have changed the way that the French interconnector is represented in the calculation of generation surplus and published on the balancing mechanism website at www.bmreports. This change was agreed with Ofgem and communicated to all market participants via an Elexon circular. For last winter the value of the contribution from the French interconnector was set at the technical capacity of 2GW export from France. However, recent experience has shown that the actual volume and direction of flow is very volatile and can be anywhere in the full range of 2GW export or 2GW import.

The actual volume and direction of flow is dictated by those parties that trade across the interconnector and has been seen to be directly dependent on mainland European generation / demand conditions and the differential in electricity prices between mainland Europe and the UK. For this reason we believed that including the full 2GW export from France was misleading and could present a false assessment of security. It was therefore considered prudent to reduce the forecast contribution from the French Interconnector to 0GW.

In the case of the Scottish interconnector the value included in the published data remains at the expected export capacity of 2.2GW. In practice actual conditions on this interconnector have been far less volatile and it is reasonable to assume an export from Scotland for this coming winter. However, it should be noted that the actual volume and direction of flow will be dictated by the Scottish generating companies.

Forecast information is not provided to NGT and it is conceivable that values less than 2GW export from Scotland could materialise.

Generator Mothballing

In the JESS report published jointly by the DTI and Ofgem it was identified that information concerning the status of mothballed generation and the alternative fuel capabilities of CCGT's was not available and that if this could be provided a more robust assumption of electricity security of supply would be possible. At the request of the DTI and Ofgem NGT has recently collected this information via a questionnaire sent to all generating companies. Recognising the potentially commercially sensitive nature of this information and the concern expressed by some companies the data has been included in this report on an aggregate basis only.

From the most recent information provided to us by the generating companies, there is some 4.2GW of mothballed plant. Of this around 2.6GW of mothballed plant has the physical potential to be returned before or during this winter. However their advice is that only 0.8GW of this is likely to be returnable in practice due to the challenges involved. The following table represents a pragmatic view of the potential for mothballed generation return.

Timescales for mothballed generation return:

	0-3 months	3-6 months	6-12 months	12-24 months
Generation Capable of being returned (GW)	0.8	0.7	1.6	1.1

Demand Side Participation - Customer Demand Management

Demand side actions can be facilitated in a number of different areas in the electricity market. Clearly, the most direct involvement is a decision to buy power forward and consume electricity. However when prices are high, customers can decide to reduce their demand to avoid the high prices. This is known as Customer Demand Management, and it is also undertaken in order to reduce demands over potential triad (peak demand) periods and so reduce customer's liability for transmission network use of system charges.

It is not known exactly how much customer demand management occurs. However, there were 3 companies that notified National Grid of CDM during the 2002/2003 winter period with the maximum notified during this period was 652MW. This compares with a maximum of 383 MW notified in 2001/2 and 583 MW notified in 2000/1.

Observations of demand over peak periods indicate that there is an un-notified volume of around 200 – 300 MW, which is taken into account in our demand forecasts.

Demand Side Participation – Balancing Services Contracts

In addition to the above we have sought a number of specific balancing services that will allow demand side participants to provide a service to NGT as an alternative (i.e. competitor) to generation. These innovative services have not made a material impact on the overall generation / demand picture but may develop.

Frequency Response Service

The Frequency Response Service consists of automatic actions that happen within seconds in response to a large change in frequency (e.g. when a large generator trips off the system). In generators, this would normally be provided by governor action on synchronised plant. On demand side, it is initiated using low frequency relays to trip demand. In order to provide a reliable service, there has to be a reasonably steady and predictable demand so that a physical effect will occur when required. Individual contracts are struck either directly with individual response service providers or via agents who provide an aggregated service on behalf of a number of providers. In addition, we have developed a probabilistic service where individual intermittent loads (e.g. steelworks) are aggregated together to provide a firm service. Demand Side participation has increased from 2.6TWh of total response holding to 2.8TWh in the last financial year. This now represents 29% of the total market share of frequency response held on the system.

Fast Reserve

Fast reserve is an instructed service (demand or generation) that is required to respond within two minutes notice and be capable of delivering at least 50MW at a ramp rate of 25MW/minute or more. The service is mainly provided by fast acting generation plant (e.g. pumped storage), and is required to meet sudden demand changes (e.g. TV pickups). Contracts are offered on the basis of monthly tenders. Demand side providers are large demands that can reduce demand at very short notice, and also radio tele-switching of domestic demands in off-peak periods.

Standing reserve

At certain times of the day NGT needs extra power in the form of either generation or demand reduction to be able to deal with actual demand being greater than forecast demand and plant breakdowns. This requirement is met from synchronised and non-synchronised sources. NGT procures the non-synchronised requirement by contracting for Standing Reserve, provided by a range of service providers including generating units, demand reduction and independent generating plant.

Demand side standing reserve in this context typically refers to units that are below 50MW and can consist of sites with demand and generation. The service must be capable of delivery within 20 minutes from instruction and be of at least 3MW in size. We cannot always be certain whether the service is provided by genuine demand reduction or the running of on-site supplies on a site specific basis, although metering does provide the total delivery volume.

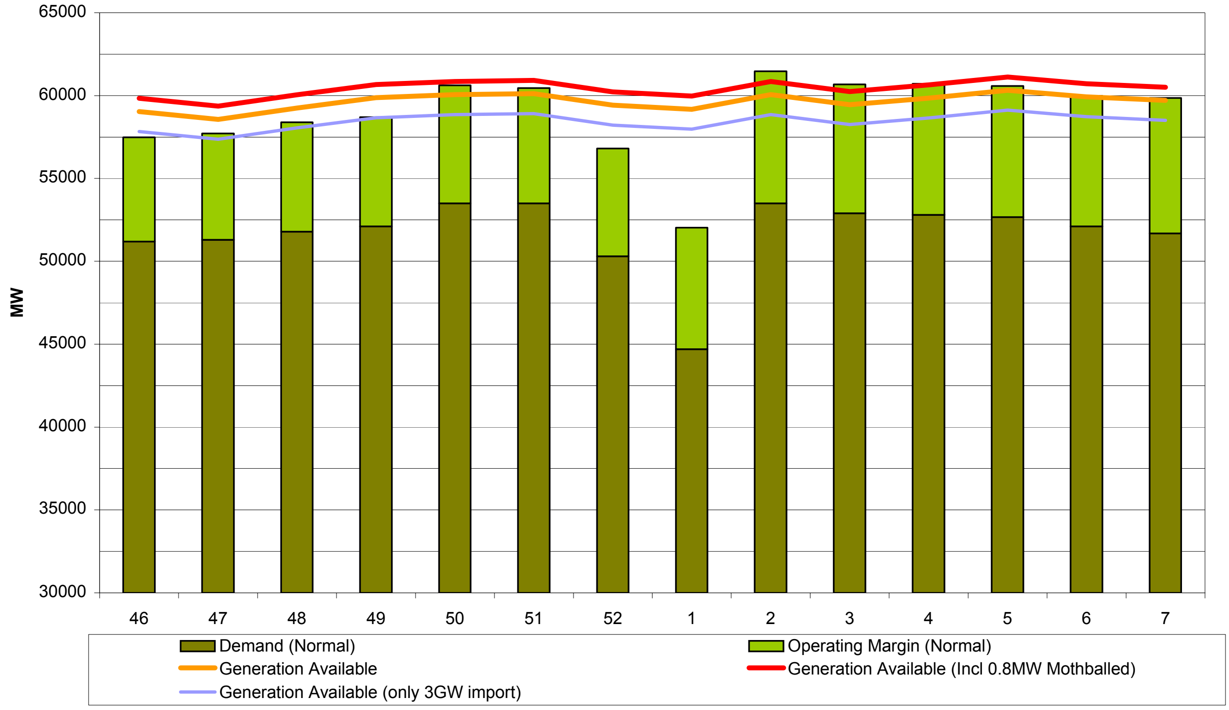
Standing Reserve is currently contracted annually via a competitive tender process, notification is given via the NGT web site and published in Utility Week. 571 MW of Demand has been contracted for 2003/4, compared to 464 MW for 2002/3. This represents 29% of the total standing reserve currently held.

Contingency reserve

A new service to provide demand reduction with longer notice (1½ hours) than Standing Reserve was recently agreed with an aggregating agent. A capacity of up to 140 MW is made available on a daily basis. By trailing this service this winter we can gain the necessary experience and if successful it may be further developed and will ultimately reduce our generation surplus requirements.

Forecast position for Average Winter Conditions 2003/004

Taking account of the above information, the graph below shows an optimistic forecast position for this winter. It assumes that the interconnectors are at maximum import and that there is no gas interruption to CCGT's.



The graph reflects the forecast average peak demand for the winter of 53.5GW, and with full export from Scotland and the French interconnector the excess generation over demand will be 6.0GW.

It also shows the potential for an increase surplus of 0.8GW over average winter peak demand if more mothballed plant is returned.

However, over the winter peak last year the total imports were actually 3.0GW. If we assume the same outturn for this coming winter's average demand peak, the surplus would be between 4.8GW and 5.6GW depending on the view taken of mothballed plant return.

Section C – Gas / Electricity Interaction

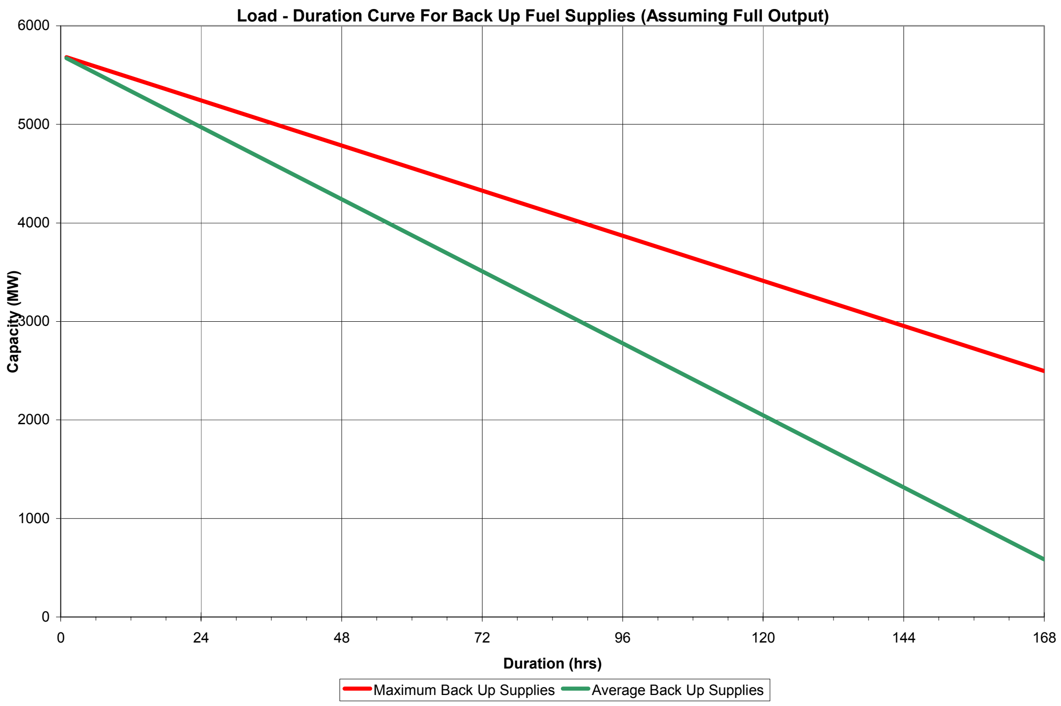
Interruptible gas fuelled generation

We anticipate that in an average or cold winter there will be a strong incentive on gas-fired generators to continue to generate, principally due to their expected forward sales position and the imbalance/market prices that would be set. The impact of gas interruption on electricity generation will be further mitigated by those able to switch to alternative fuels, unless generators have inadequate back-up arrangements or their reliability on back-up fuel is low. However 2.7GW does not have a distillate back up fuel source. Recognising the significant advantage early notification of potential interruption has to the successful changeover to alternate fuels we will endeavor to give as early as possible notice of interruption.

It is thought unlikely that merchant generators would chose to interrupt their gas supply at times of high electricity demand as the high electricity imbalance price exposure can be expected to encourage generation. However to some extent this will depend upon the overall gas supply position.

We are assuming that all CCGTs with the capability, if interrupted (whether by a shipper or NGT), will attempt to switch to alternative fuel and are capable of doing so. We have recently on behalf of Ofgem sought to confirm the current position with respect to alternative fuel capabilities and duration.

Based on Registered Capacities, taking into account commissioning and mothballed plant, the total CCGT output capacity will be 21.6 GW for winter 2003/04. Gas supply under NGT/shipper interruptible arrangements is expected to affect up to 8.6GW of plant. The total CCGT distillate capacity across all firm and interruptible gas supplied power stations is 5.9 GW. The smoothed load duration curve for distillate fuel capacity is detailed below.

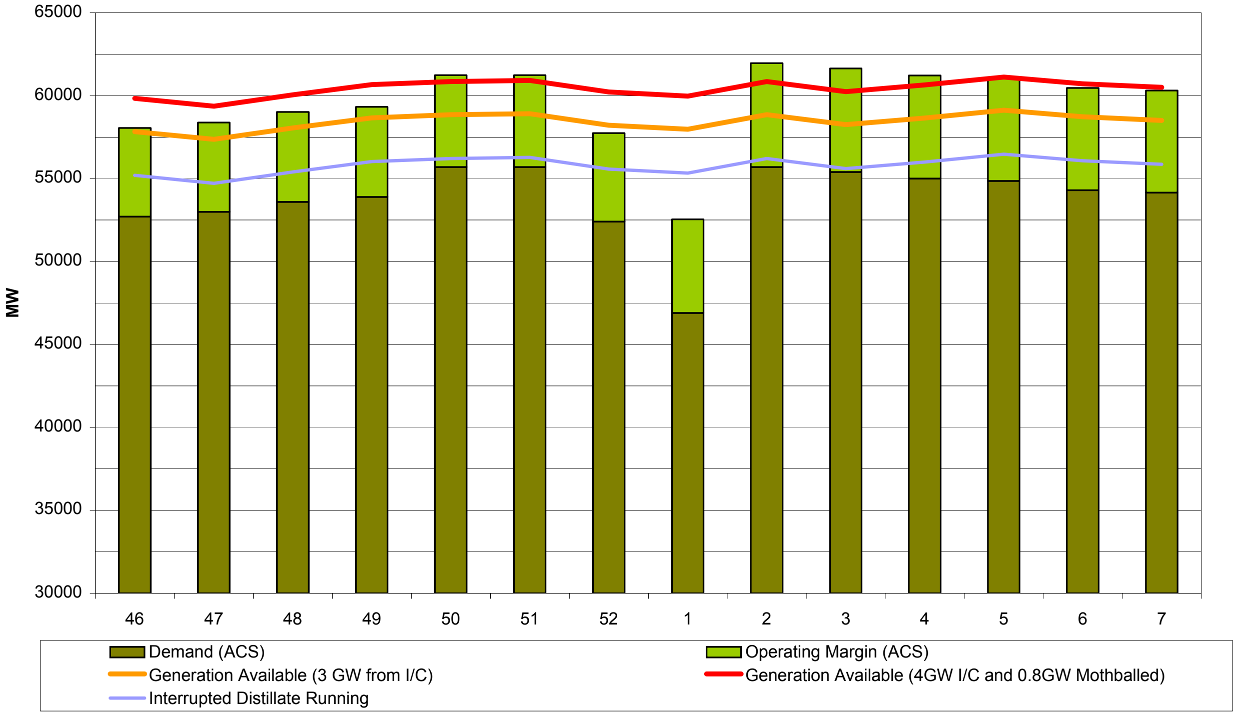


The relationship between gas interruption, mothballed plant, and interconnector variability with cold winter demand

The graph below shows the potential impact of generation assumptions set against the cold winter demands. The levels of demand for each week reflects the peak requirement that has a 50% probability of occurring within any winter.

This shows the total maximum potential surplus over cold weather demand will be 4.6GW. If 0.8GW of mothballed plant is not returned, and assuming the total import for the interconnectors is reduced to a more central view of (say) 3GW, the surplus is reduced to 2.6GW.

With gas interruption established we have shown that a minimum of a further 2.7GW would be unavailable. This would lead to a deficit of 0.1GW over cold winter demand. In this scenario there is no margin at all for on the day generation outage and voltage reduction is likely.



While the ACS Weekly Peak Demand is shown across the whole winter, historically the winter peak normally occurs in the two full working weeks before the Christmas / New Year holiday or the two full working weeks afterwards. It is mostly likely to occur between Monday and Thursday. This means that there are sixteen days across any winter that are generally most likely to see the peak electricity demand. Over the recent run of mild winters the daily peak demand has only outturned close to ACS Demand on around four occasions each winter between November and February.

However, the position would be substantially improved if commercial or other mechanisms were introduced to allow gas to be restored to CCGTs over the relatively short evening peak in electricity demand. We are proposing changes to allow this to happen. These include:

- Facilitating the ability for shippers to trade their interruption obligations between them. This would be beneficial for example when a CCGT with interruptible gas supplies is interrupted at a time when electricity margins are tight. There would be a commercial opportunity for the shipper to substitute the interruption of the CCGT with the interruption of an alternative gas demand subject to operating conditions on the NTS.

- Facilitating a new service to enable interruption of gas to CCGT's (by both shippers and NGT) to be effectively relieved over the electricity peak demand hours.
- Back-stop arrangements to enable the electricity and gas system operators to co-ordinate actions in an emergency to further promote the security of supply. (For example allowing the gas system operator to temporarily direct the restoration of gas delivery to interrupted CCGTs over the peak electricity demand periods, where market mechanisms had not already achieved this, and where it had been established that it would avoid an electricity supply shortage).

Evolution of CCGT market participation

Given the commercial drivers in electricity we anticipate that there is further scope for CCGTs to operate with higher generation level variability than has hitherto been seen. Thus the power station loads might be expected to demonstrate higher rates of offtake flow variation thereby effectively increasing the use of within-day linepack by that type of user.

Additionally it is possible that in operating the gas system we are also faced with much greater uncertainties in respect of CCGT demand if such loads provide an increased proportion of the flexibility needed to satisfy the electricity balancing mechanism.

We believe that the electricity market would be the primary focus of power station operators given the nature and effect of the shorter balancing period in electricity, and particularly higher imbalance cashout exposures. The gas balancing regime affords a longer balancing period so generators will have an option to manage their gas balance by changes, both in respect of physical flow changes and/or gas trading, later in the gas day.

The combined effect of the three factors identified above might be greater within-day gas flow variations as players manage and optimise station requirements.

On occasions we have already found the extent and unpredictability of within day flow rate variations on the gas system challenging. Therefore, we will be keeping these developments under review to ensure that the uncertainties associated with such changes do not increase, leading to potentially inefficient or unnecessary balancing actions.

Our balancing tools have been developed with a residual balancing objective assuming that the commercial incentives in the regime will deliver gas flows on the system sufficiently close to design assumptions that they satisfy operational requirements. Provided this remains the case we believe that the regime can be operated in an economic, efficient and co-coordinated manner.

Current modeling and use of linepack suggests we will be able to continue to manage within-day flow rate variations. This depends on no material increases in input and offtake flow rate variations, which would further reduce the availability of linepack flexibility. We will be working with OFGEM and Shippers to ensure that we receive accurate and timely information in relation to this.

We remain of the view that should further increases in the within day flow variation become apparent it will be essential to consider reform of the regime, although as previously stated we would advocate incremental reform that might better enable the preservation of the daily balancing regime.

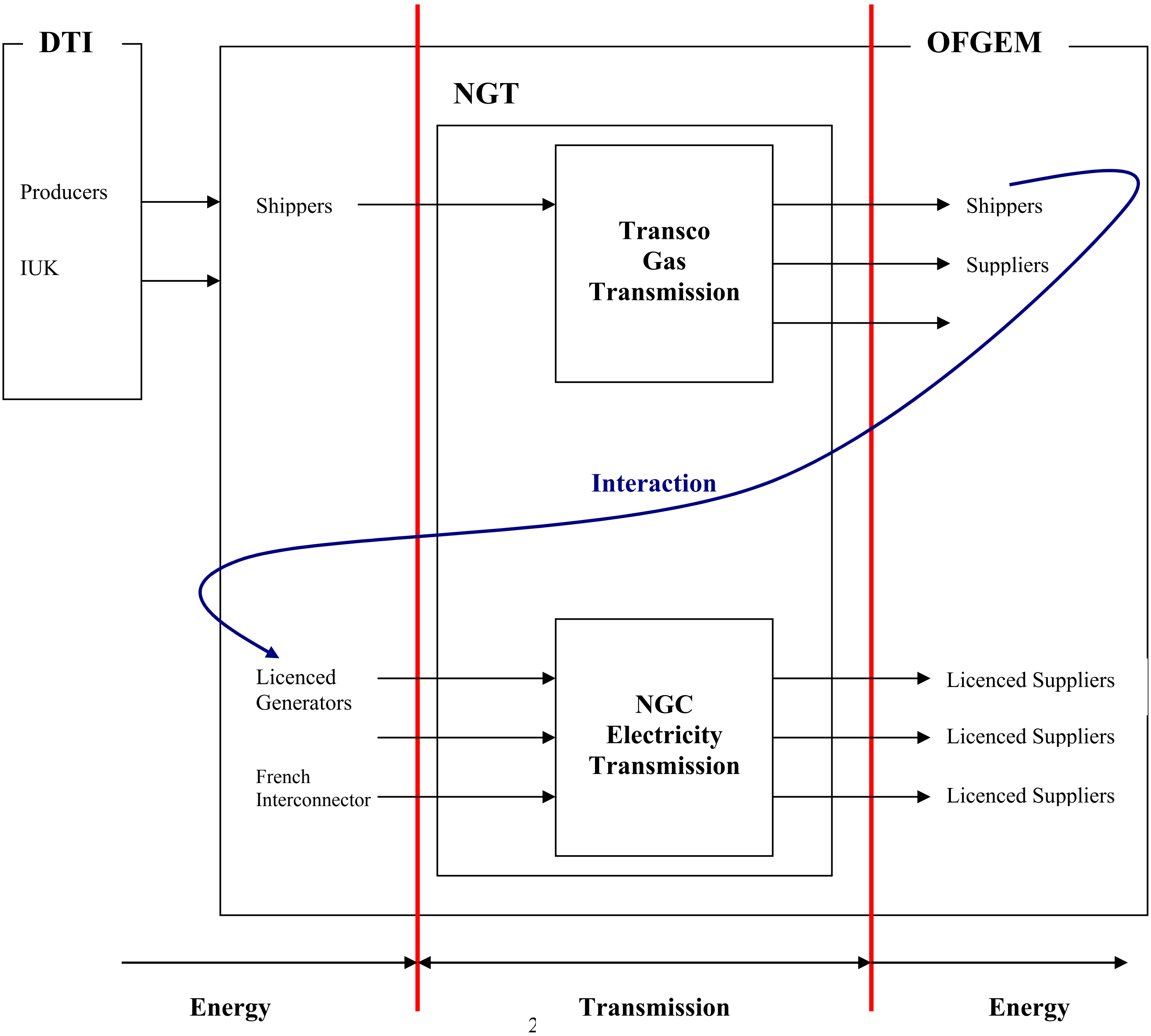
Incremental Gas Balancing Reform

One particular issue is that our primary "commercial" market-based tools do not always result in timely flow rate changes as they are, effectively, indirect tools with extent of impacts determined by the complex interactions between various commercial incentives. Thus the tools have a considerably less certain effect than the tools available to NGT in the electricity market.

The incremental reform that we believe would lead to more reliable physical outcomes from our balancing actions would be to provide better incentives on nominations by shippers. For example the current scheduling charge, which is based upon the nomination prevailing at the end of the gas day, could be supplemented by a scheduling charge based on the nomination at the beginning of the gas day. This would incentivise shippers not to unwind the effect of accepted locational actions by subsequent re-nomination during the day. In addition, it would have the further benefit of providing better incentives on shippers to provide more accurate estimates of end of day flows, earlier in the gas day. We recognise that such a change would reduce shippers commercial flexibility within day, but believe that if necessary these concerns could be mitigated by limiting the application of the ‘start of day scheduling charge’ to difficult days.

Appendix A

Schematic Showing Different Parties' Role in Energy Market Security



Appendix B

Key Terms

"1 in 20"

The 1 in 20 peak day gas demand is the peak day demand that, in a long series of winters, with connected load being held at the levels appropriate to the winter in question, would be exceeded in one out of 20 winters each winter being counted only once.

"1 in 50"

The 1 in 50 severe annual gas demand is the annual demand represented by the area (above a demand threshold of zero) under the 1 in 50 load duration curve, being the curve which, in a long series of years, with connected load held at the levels appropriate to the year in question, would be such that the volume of demand above any given demand threshold (represented by the area under the curve and above the threshold) would be exceeded in one out of 50 years.

ACS

The Average Cold Spell (ACS) demand is determined in a similar way to that used when determining "normal" demands. One of the key inputs into the demand forecasting process is the forecast weather conditions for a particular week. In order to generate this forecast the weather conditions seen in each week over a historic 22 year period are analysed. This analysis then gives a probabilistic distribution of the expected weather conditions for future weeks and it is this distribution that is key to determining the ACS demands.

To calculate a ***mean*** weekly demand forecast the ***mean*** expected weather conditions from the probabilistic distribution are fed into the demand forecasting model. For the weekly ***ACS*** Demand Forecast, the weather conditions corresponding to the 12th percentile of the weather distribution are used in place of the mean weather conditions. That is to say that there is a 12% chance that the weather conditions in the week itself will be worse than those in the ACS forecast. The ***ACS*** demand forecast is then calculated by feeding these ***ACS*** weather conditions into the demand forecasting model.