Annex A - Further Analysis of 2005/06

Analysis of the Winter Weather

Weather severity in gas terms is generally measured between October and March inclusive. On this basis, 2005/06 was 1 in 4 warm in the context of all winters since 1928/29.

The Met Office analysis for the mean temperatures (November to March inclusive) based on a 30-year long-term (1970 - 2000) average from 180 observing sites in the UK is shown below in Table A.1. On this basis, the mean temperature for the UK was 0.5 ºC colder than normal.

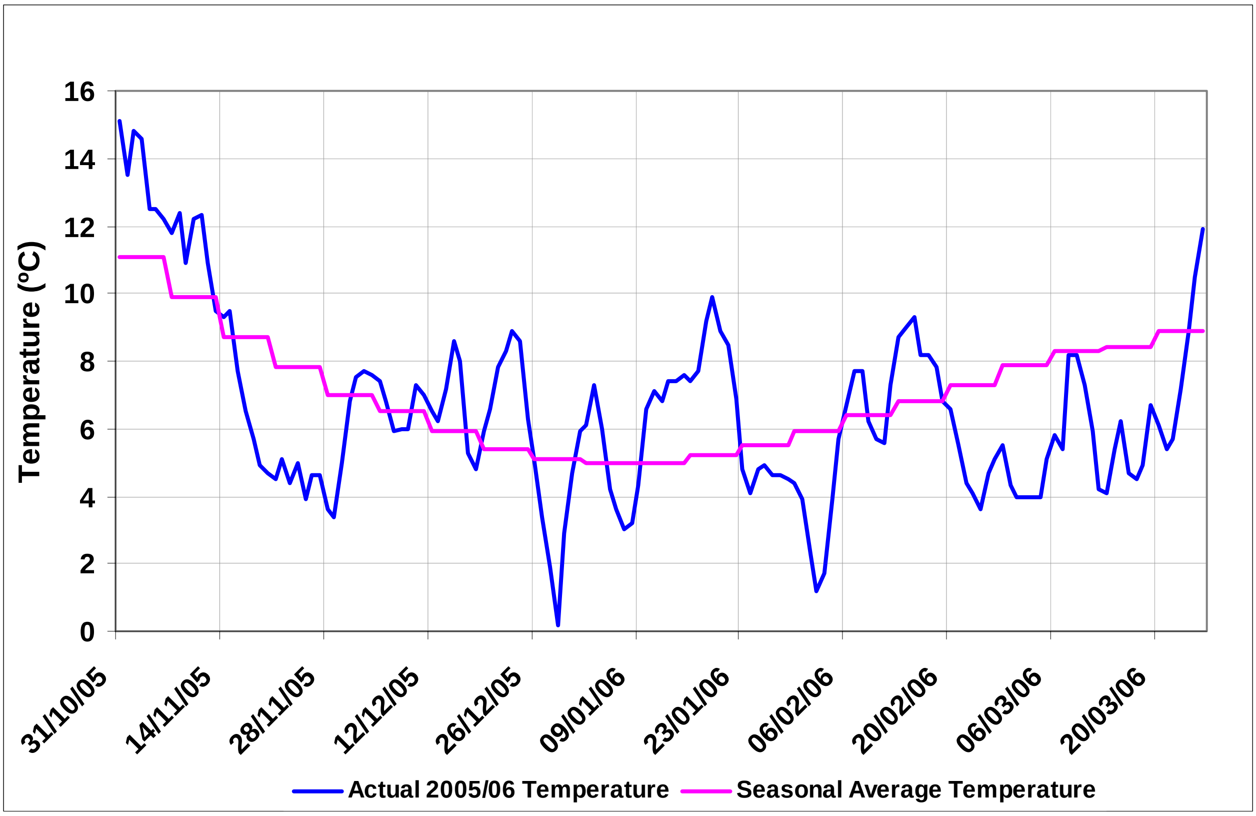
Table A.1 – Mean Temperature, Winter 2005/06

	Mean Temperature		Comments
Region	**Actual (ºC)**	**Difference from Normal (1971 - 2000) (ºC)**	
UK	3.5	-0.5	Coldest since 1995/1996
England	3.6	-0.9	Coldest since 1995/1996
Wales	3.7	-0.8	Coldest since 1995/1996
Scotland	3.0	0.1	Coldest since 2000/2001
England & Wales	3.6	-0.9	Coldest since 1995/1996

Source: Met Office

The mean day-time temperature between 09:00 and 21:00 was 5.5 °C; this was 1.5 °C colder than that of winter 2004/05. Figure A.1 shows the daily average temperatures for the winter, compared against seasonal average day-time (07:00-21:00) temperatures (based on 30 winters, 1974-2004).

Figure A.1 – Daily Temperature for Winter 2005/06 Against Normal



Analysis of Sustained Cold Spell in March 2006

As March 2006 was a notable month for its low temperatures, this has been further analysed in more detail in this section.

Table A.2 shows temperature for March 2006. For this month, all areas were colder than average (by 1.0 to 1.4 ºC); in particular for Scotland, March was colder than any of the 3 standard winter months (Dec/Jan/Feb) by around 0.5ºC. The last time this happened for Scotland was March 1976.

Table A.2 – Temperature for March 2006

	Maximum Temperature		Minimum Temperature		Mean Temperature	
Region	**Actual (ºC)**	**Difference from Normal (ºC)**	**Actual (ºC)**	**Difference from Normal (ºC)**	**Actual (ºC)**	**Difference from Normal (ºC)**
UK	7	-1.5	0.8	-1.1	3.9	-1.3
England	7.8	-1.5	1.4	-1	4.6	-1.3
Wales	7.3	-1.3	1.5	-1	4.5	-1
Scotland	5.3	-1.6	-0.4	-1.2	2.5	-1.4
England & Wales	7.8	-1.5	1.4	-1	4.6	-1.2

Source: Met Office

Further Analysis of 2005/06 - Gas

Demand

2005/06 Demands
Winter 2005/06 gas demands compared to demands under cold, normal and warm conditions can be found in Figure 3 of Chapter 1.
Table A.3 shows that the three highest gas demand days of the winter were the first three days of February 2006. The highest demand day in the previous winter was 419 mcm (4,597 GWh) on 24 February 2005.

Table A.3 – Highest Gas Demand Days in Winter 2005/06

Date	Demand (mcm)	Demand (GWh)
1 February 2006	411.34	4,524.74
2 February 2006	410.86	4,519.46
3 February 2006	393.76	4,331.36

Demand response

Table A.4 compares winter 2005/06 severity and the coldest day to the previous two winters. Despite 2005/06 being colder than the two previous years, both in terms of the coldest day and overall severity, Figure A.2 shows that demands were lower on the day of highest demand and across the load duration curve.

Table A.4 – Winter Severity – 2003/4 - 2005/06

	Winter severity (October to March)	Coldest day
2005/06	1 in 4 warm	1 in 3 warm
2004/05	1 in 15 warm	1 in 10 warm
2003/04	1 in 8 warm	1 in 6 warm

Figure A.2 – Demand Load Duration Curves (2003/04 – 2005/06)

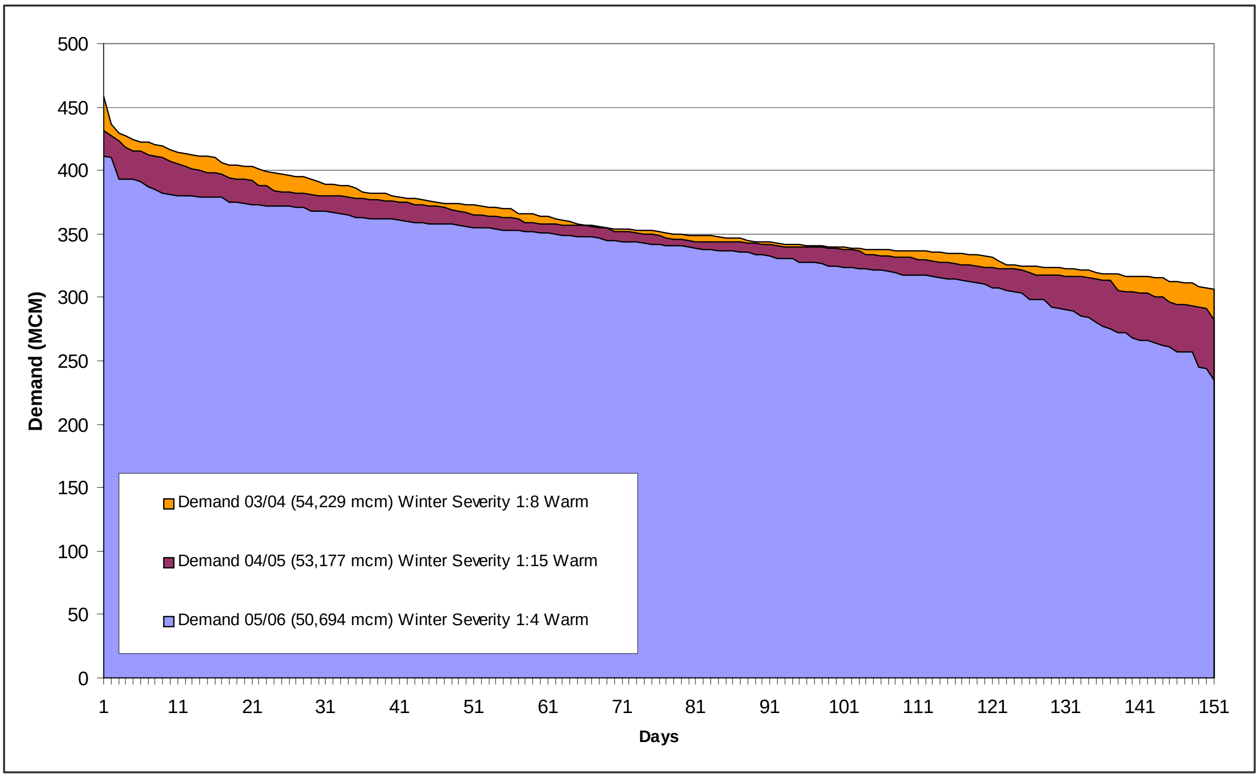
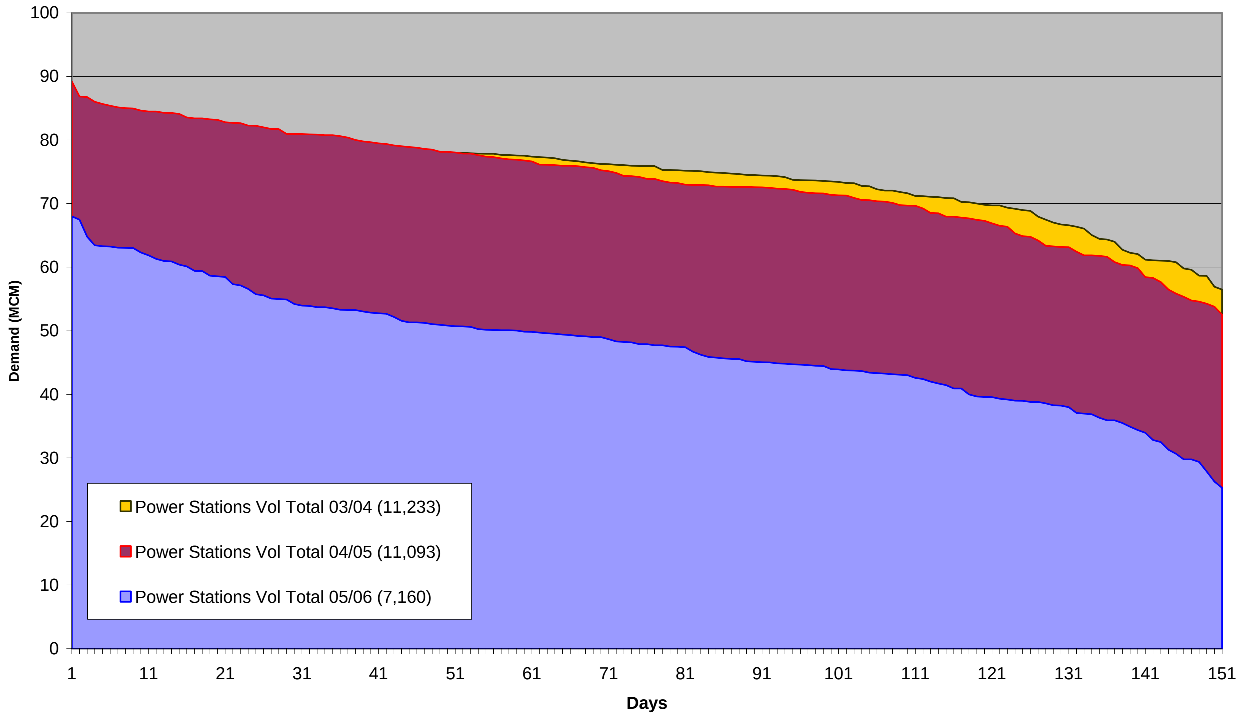


Figure A.3 shows that roughly 20 mcm/d, i.e. the majority, of this demand response was due to power station load and that this occurred deep into the load duration curve.

Figure A.3 – Power Station Load Duration Curve (2003/04 – 2005/06)



Comparison with Pre-Winter Modelling

Figure 4 in Chapter 1 shows demand compared to the winter outlook simulation model. Demand response principally occurred from the latter half of November as the weather turned colder and extended right through March.

The following figures break down the demand and its response into its component parts. Figure A.4 and Figure A.5 show LDZ non-daily metered demand and LDZ daily-metered firm demand. These largely followed modelled projections (although slightly depressed on average) and were non-responsive to changes in System Average Price (SAP).

Figure A.4 – LDZ Non-daily Metered (NDM) Demand in Winter 2005/06

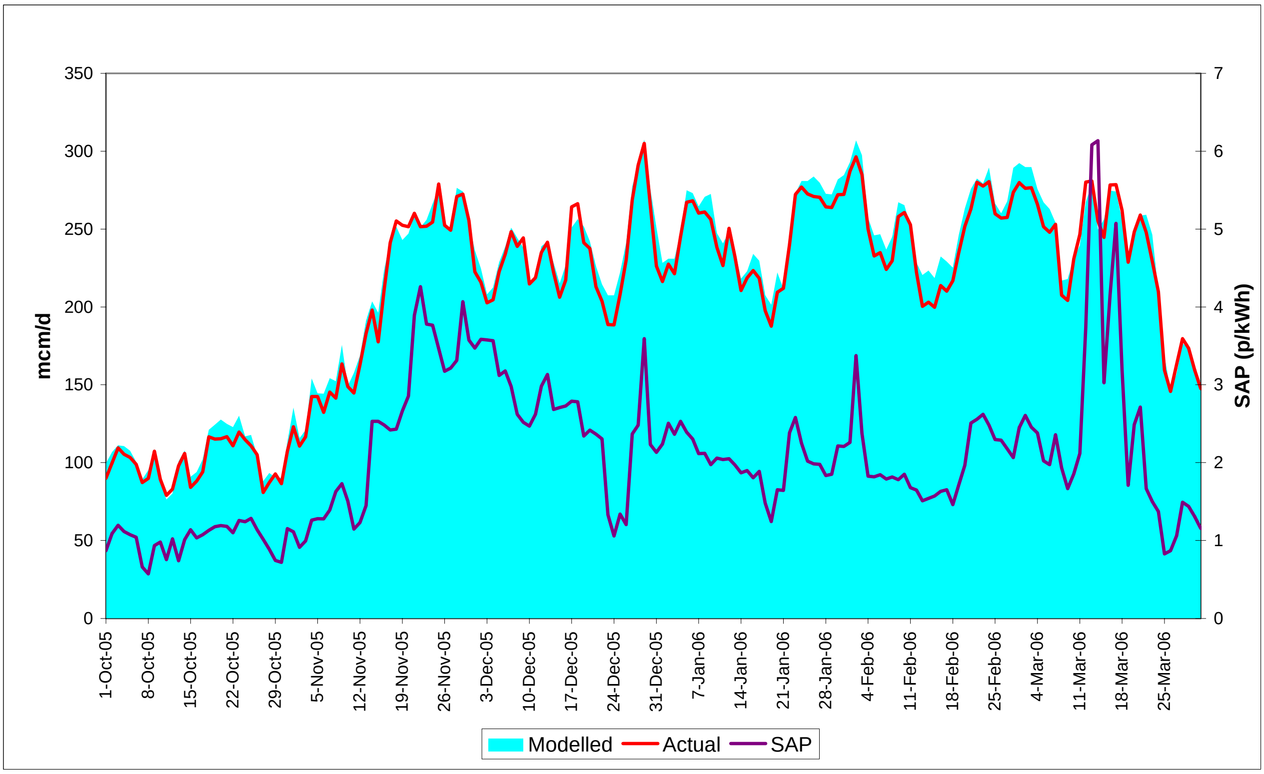
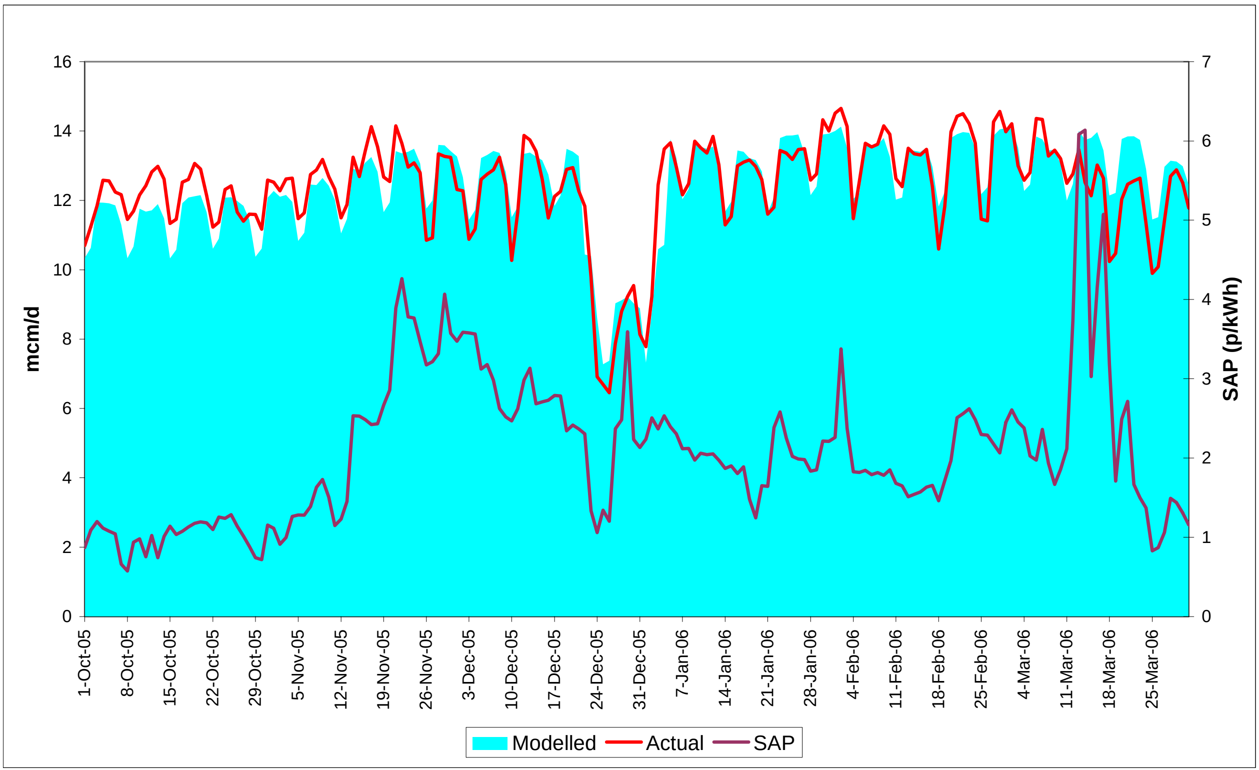


Figure A.5 - LDZ Daily Metered (DM) Firm Demand in Winter 2005/06



Conversely, Figure A.6 to figure A.8 show NTS demand and LDZ daily metered interruptible demand dropping below modelled projections particularly during periods of high prices. Note that the modelled NTS Power Station load in Figure A.6 included a degree of load response based on the experience of previous winters, but actual response exceeded this.

Figure A.6 – NTS Power Station Demand in Winter 2005/06

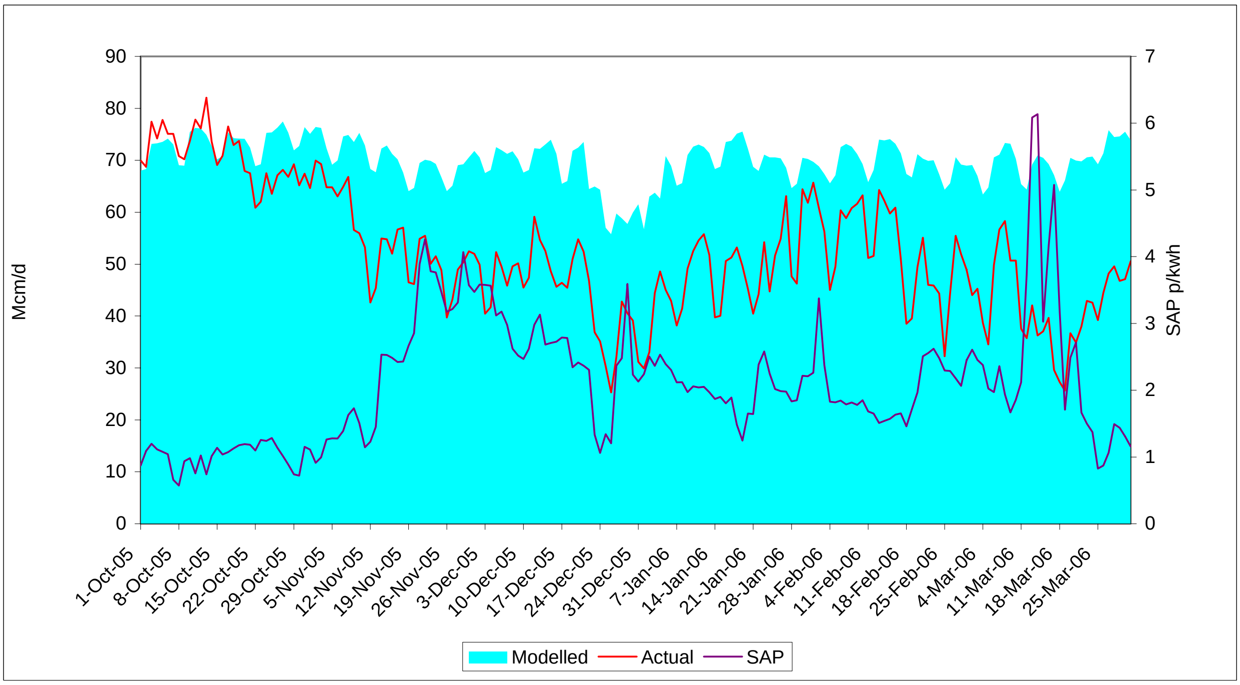


Figure A.7 – NTS Industrial Loads Demand in Winter 2005/06

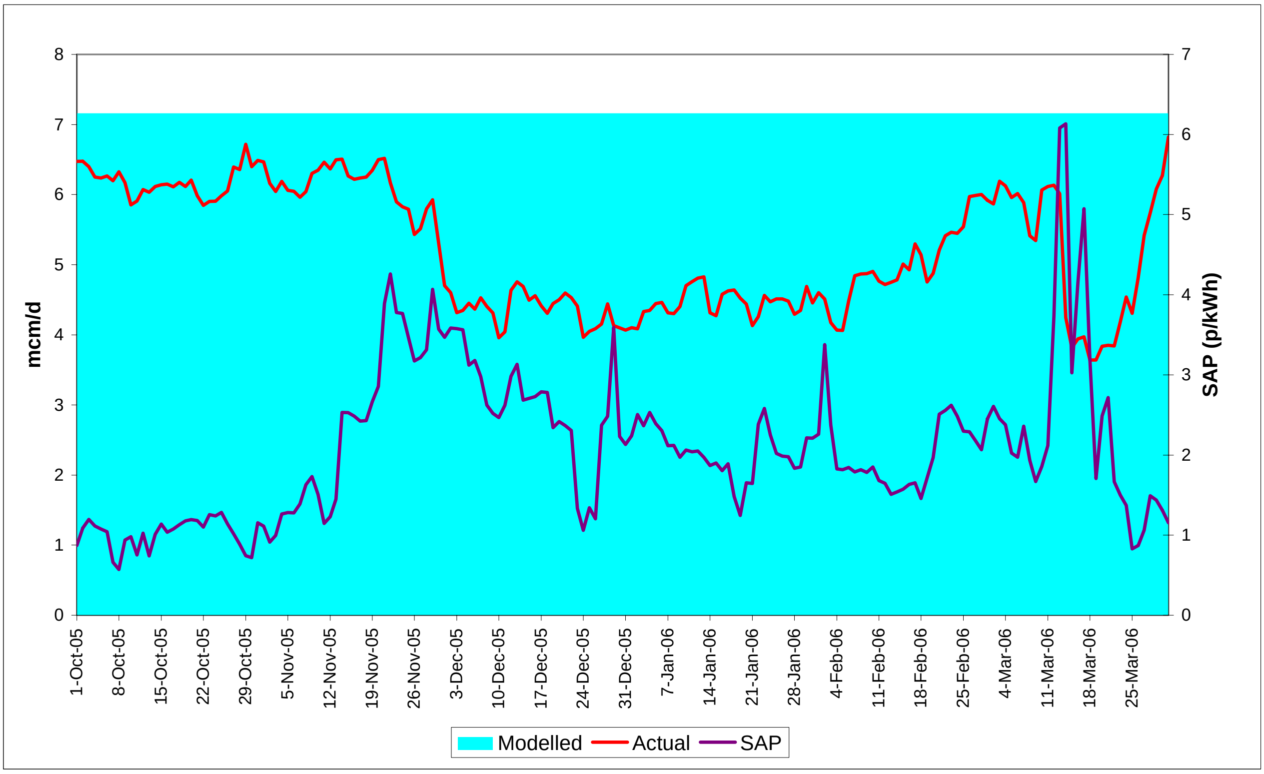


Figure A.8 – LDZ Daily Metered (DM) Interruptible in Winter 2005/06

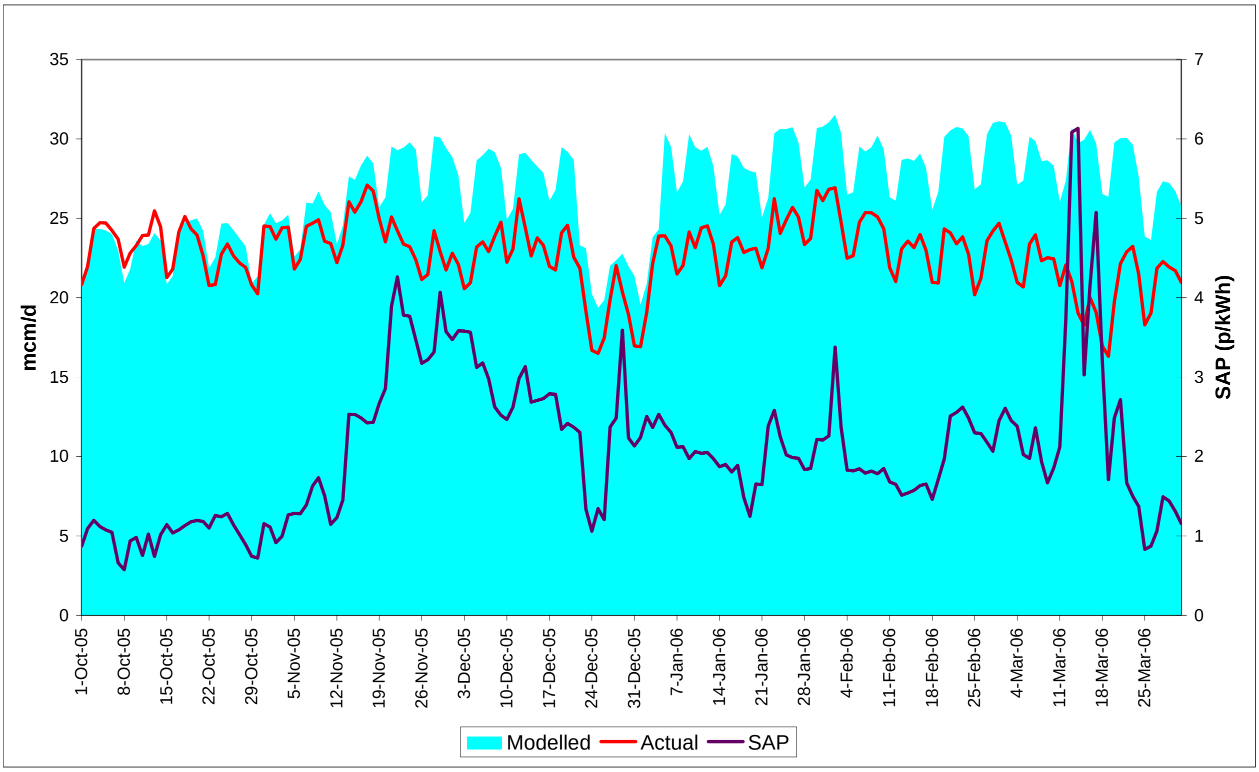
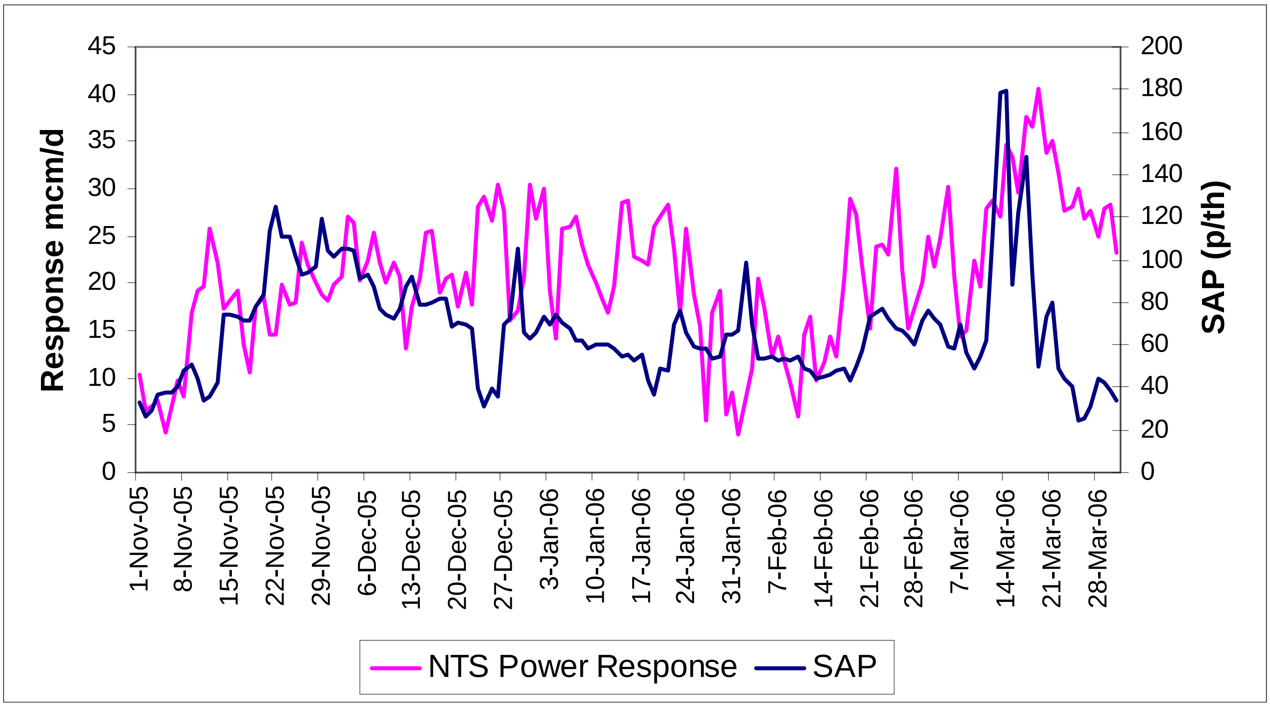


Figure A.9 shows NTS Power Response compared to SAP over the winter. NTS Power Response is the difference between the modelled and actual NTS power demand shown in Figure A.6. NTS Power Response exhibits a weekly cycle with more response at weekends. There appears to have been less response in early November and early February, when SAP was relatively low, and more response in mid March when SAP was relatively high.

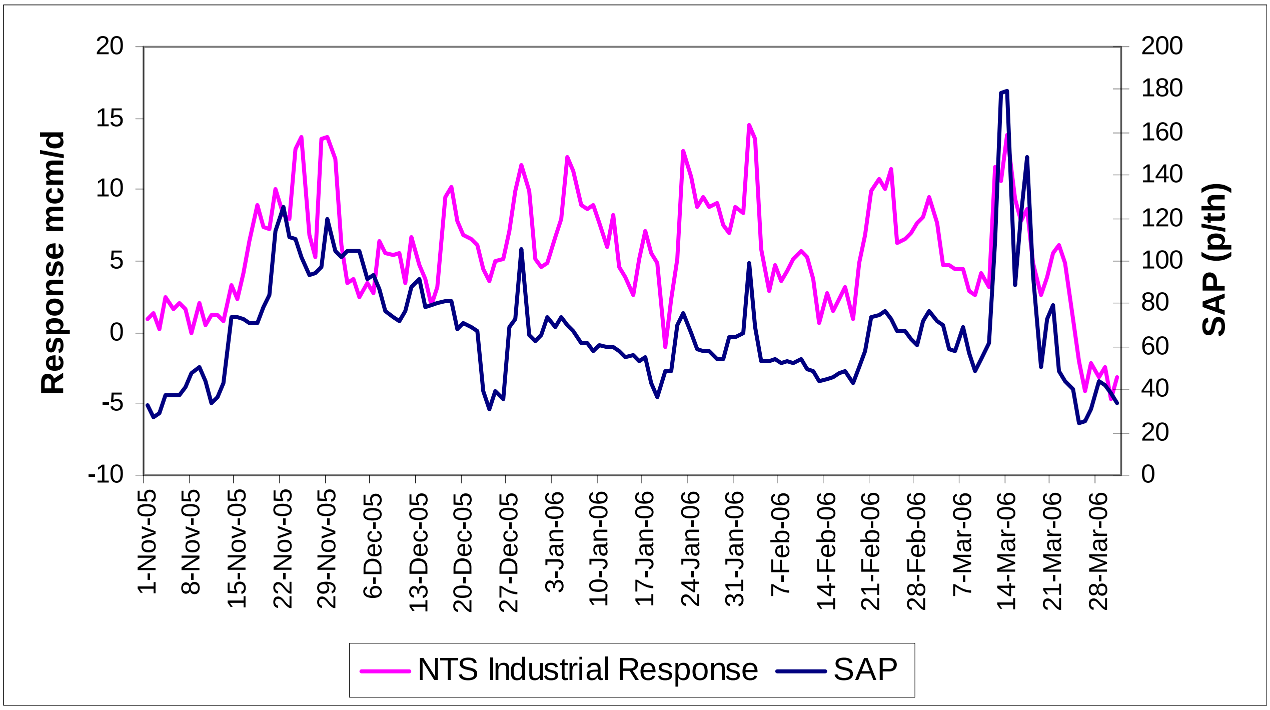
Figure A.9 – NTS Power Response vs SAP in Winter 2005/06



Statistical analysis showed poor correlation between daily NTS Power Response and daily SAP. However, a stronger relationship was found between daily NTS Power Response and the daily dark spread or the difference between dark and spark spreads.

Figure A.10 shows NTS Industrial Response compared to SAP over the winter. NTS Industrial Response is the difference between the modelled and actual demand shown in Figure A.7. Industrial Response exhibits a much clearer relationship to SAP with many peaks and troughs coinciding.

Figure A.10 – NTS Industrial Response vs SAP in Winter 2005/06



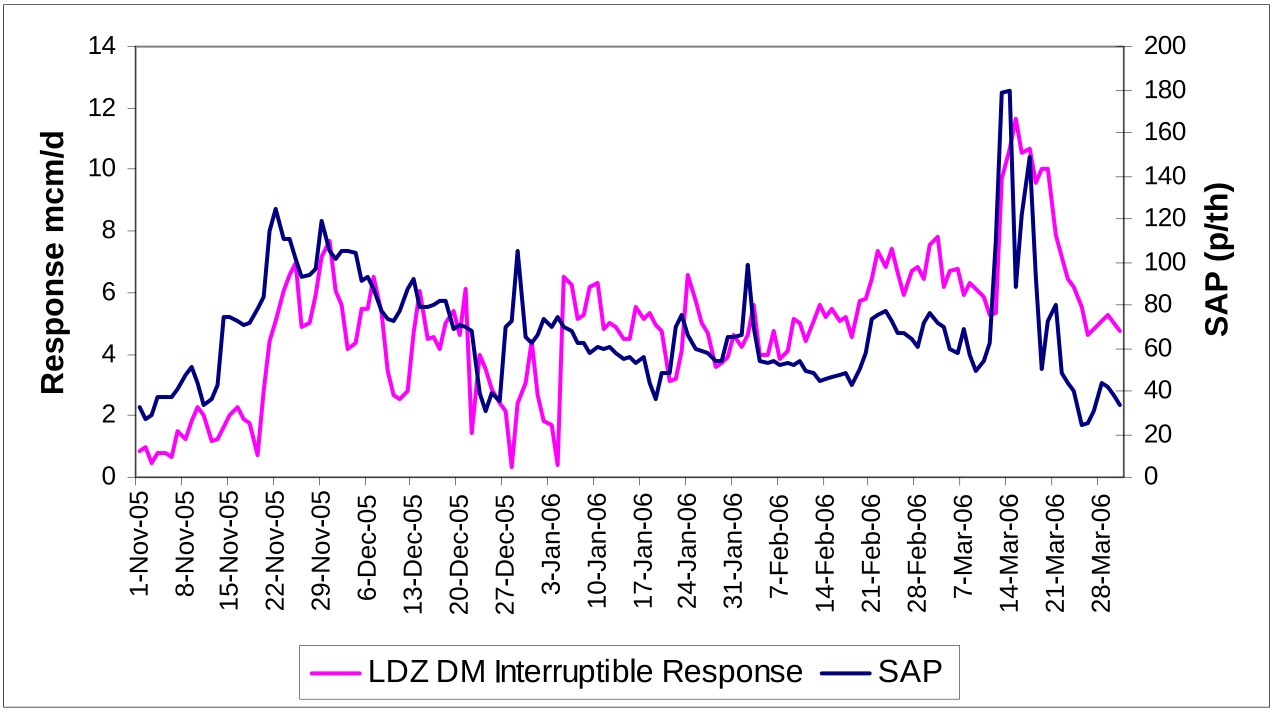
Statistical analysis in Table A.5 shows that the greatest correlation between daily SAP and daily NTS Industrial Demand response occurs on the day, i.e. that there is no time lag for this category of demand response.

Table A.5 – Analysis of Correlation between SAP and NTS Industrial Response

Offset (SAP on Day D compared to Response on Day D + x)	Correlation between SAP and NTS Industrial Response (Difference between modelled and actual demand)
0	57%
1	50%
2	33%
3	22%
4	14%
5	7%
6	6%
7	6%

Figure A.11 shows LDZ Daily Metered Interruptible Demand response compared to SAP over the winter. LDZ DM Interruptible Demand response is the difference between the modelled and actual demand shown in Figure A.8. LDZ DM Interruptible Demand response exhibits a reasonably clear relationship to SAP although a time lag is apparent between peaks in SAP and corresponding peaks in response. For example the peaks in SAP on 22 November, 29 December and 13 March correspond to peaks in response on 25 November, 31 December and 15 March respectively.

Figure A.11 – LDZ DM Interruptible Response vs SAP in Winter 2005/06



Statistical analysis in Table A.6 shows that the correlation between daily SAP and daily LDZ DM Interruptible Demand Response improves if SAP is compared to the LDZ response one to three days later. This suggests that this demand sector has a one to three day time lag before the full response can be obtained.

Table A.6 – Analysis of Correlation between SAP and LDZ DM Interruptible Response

Offset (SAP on Day D compared to Response on Day D + x)	Correlation between SAP and LDZ DM Interruptible Demand Response (Difference between modelled and actual demand)
0	46%
1	55%
2	56%
3	52%
4	43%
5	35%
6	32%
7	31%

Transportation interruption

Transmission

There was no National Grid instigated interruption on the NTS in winter 2005/06.

Distribution (National Grid Retained Networks & Independent Distribution Networks)

The total volume of Distribution Network Sensitive Load (NSL) interruption in the LDZs was 0.65 mcm, involving 30 sites. This compares with 3.1 mcm at 16 sites in 2004/05, and 4.4 mcm at 62 sites in 2003/04.

Shipper Interruption (notified to National Grid by the P70 reporting process)

For NTS sites a total of 39 P70s were received (32 Interruptible and 7 Firm) in winter 2005/06. These P70s accounted for 220 site days of shipper interruption.

On the day for which a Gas Balancing Alert (GBA) was issued (13 March 2006), one P70 was received, covering three sites with a total interrupted volume of 1.2 mcm.

For DN LDZ sites a total of 34 P70s were received (33 Interruptible and 1 Firm) for a total interruption volume of 12 mcm in Winter 2005/06.

On the day for which a GBA was issued (13 March 2006), eighteen P70s were received (17 interruptible and 1 Firm) for a total interruption volume of 1.3 mcm.

Beach supplies

Chapter 1 compares actual beach performance against forecasts. The sum of the highest deliveries of each terminal was 328 mcm/d compared to the 2005/06 maximum beach forecast of 327 mcm/d. The highest beach delivery on one day was 309 mcm (3,347 GWh) on Friday 9 December 2005 compared to the 2004/05 winter daily maximum of 331 mcm on 5 March 2005.

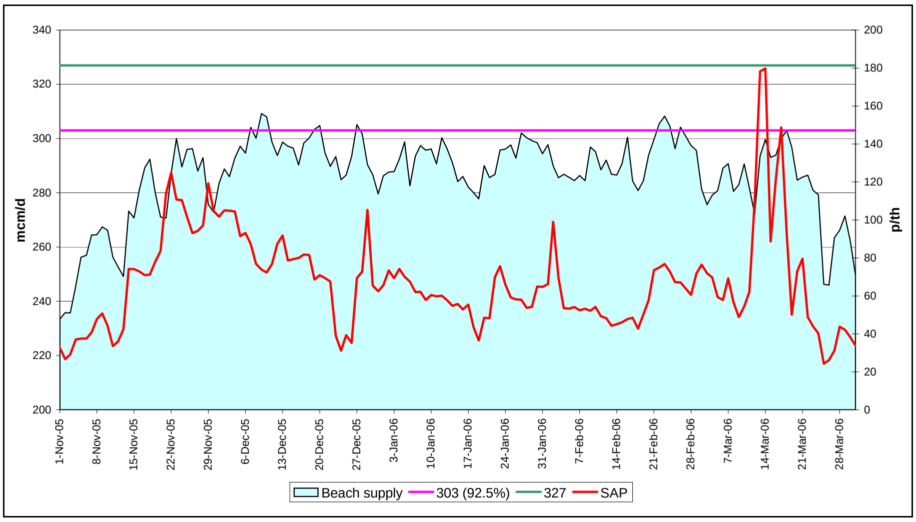
Beach v price

Table A.7 summarises monthly average beach delivery and Figure A.12 compares beach delivery to System Average Price. Together these show that beach delivery was relatively consistent between November and March despite significant swings in SAP.

Table A.7

Month	Daily Average (mcm)
Nov	270.4
Dec	295.2
Jan	291.8
Feb	292.8
Mar	280.7

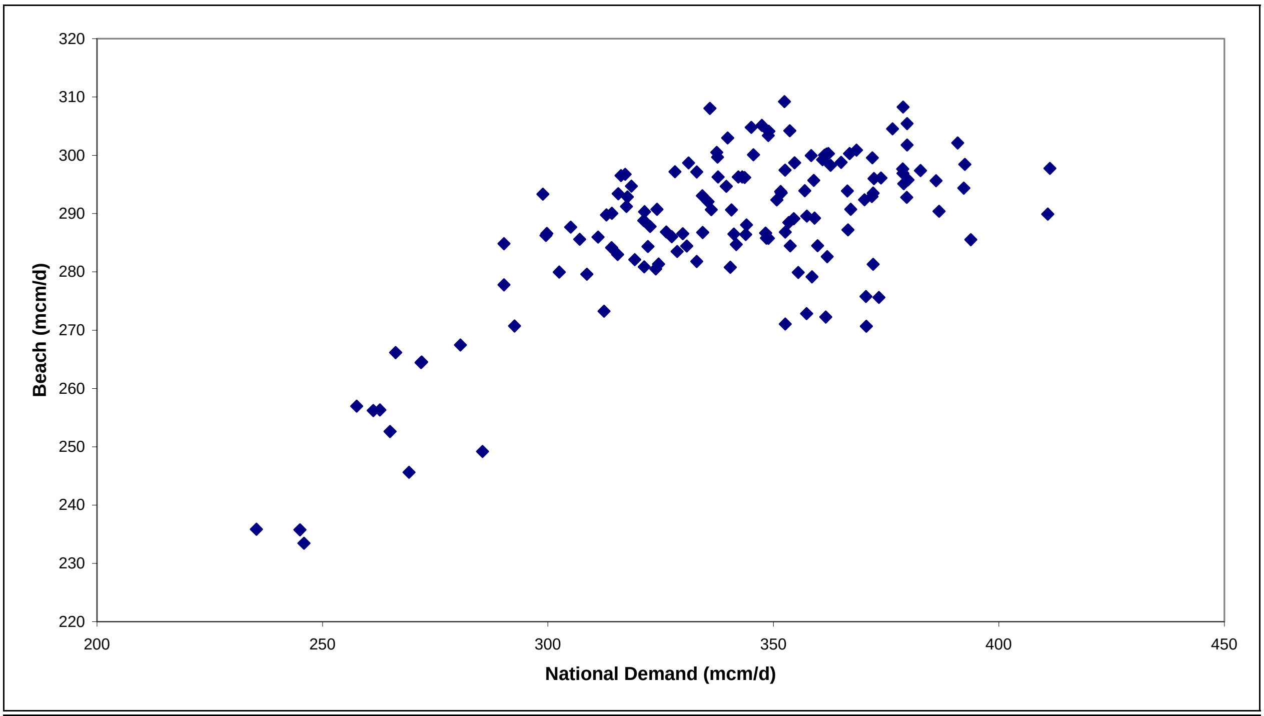
Figure A.12 –Beach Demand vs SAP in Winter 2005/06



Beach v demand

Figure A.13 compares beach delivery to national demand. A clear linear trend can be seen between beach delivery and demand for demand levels up to around 310 mcm/d. For higher demands, no clear relationship between beach supplies and demand can be seen, suggesting that fluctuations were driven by other factors such as short-term field outages.

Figure A.13 – Beach Delivery vs National Demand in Winter 2005/06



New fields

Table A.8 summarises reports of new fields coming on stream in the Heren Report - European Spot Gas Markets and Platts European Natural Gas Report.

Table A.8 – New Fields in Winter 2005/06

Field	Month reported	Reported Flow (mcm/d)
Annabel	April 2005	2.0
Forvie Area	January 2006	2.0
Horne & Wren	June 2005	2.5
Munro	August 2005	2.0
Rhum	December 2005	3.7
Saturn	September 2005	4.0
Total		**16.2**

A number of new field developments were forecast to come on-stream in time for Winter 2005/06. These contributed around 15 mcm/d to our maximum beach forecast, broadly consistent with the reported capabilities shown above.

Supply Losses

Rough incident

On 16 February 2006, the Rough storage facility was shutdown following an incident on the 3B production platform. On 1 March 2006, Centrica Storage confirmed that the unplanned outage would continue through March and April. The loss of Rough, combined with forecasts of higher demand, resulted in National Grid re-allocating the Safety Monitors and re-setting the GBA trigger level to 425 mcm/d with effect from 06:00 hours on 2 March 2006.

On 10 March, Centrica Storage issued a notice to the industry stating that Rough would not be available until at least 1 May 2006. At the time of publication, the latest notice from Centrica Storage quoted their best estimate of the date of resumption of injection operation as 1 June 2006, and said that their best estimate was that full production rates would be available from 1 October 2006.

Further to this notice, Centrica announced on 12 May 2006 that, in relation to the South Morecambe field, the need to investigate possible associated issues with cooler units similar to that involved in the Rough storage platform incident..

Other supply losses

Figure A.14 shows the number of occasions in each month that UKCS beach terminals have experienced reductions in planned flow rate of at least 1 mcm/d that lasted at least one hour (i.e. > 41,666m^3). This shows fewer winter losses in 2005/06 compared to 2004/05 although a higher number of summer losses were observed. However, as Figure

A.15 shows, the number of major supply losses (greater than 10 mcm/d for at least 10 hours) was similar to 2004/05. There were a high number of losses coincident with the March 2006 cold spell repeating the experience of March 2005.

Figure A.14 – Supply Losses in Winter 2005/06

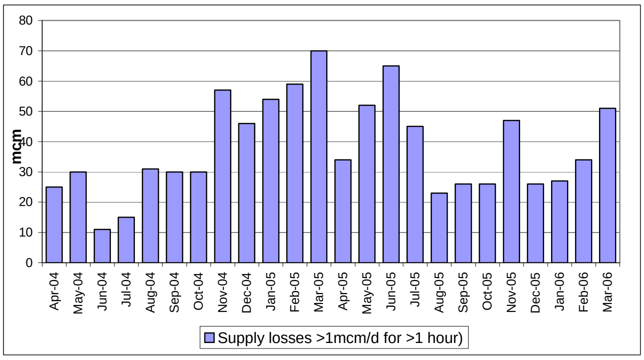


Figure A.15 – Major Supply Losses in Winter 2005/06

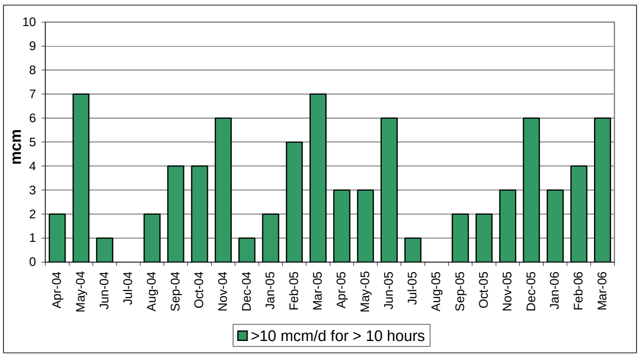
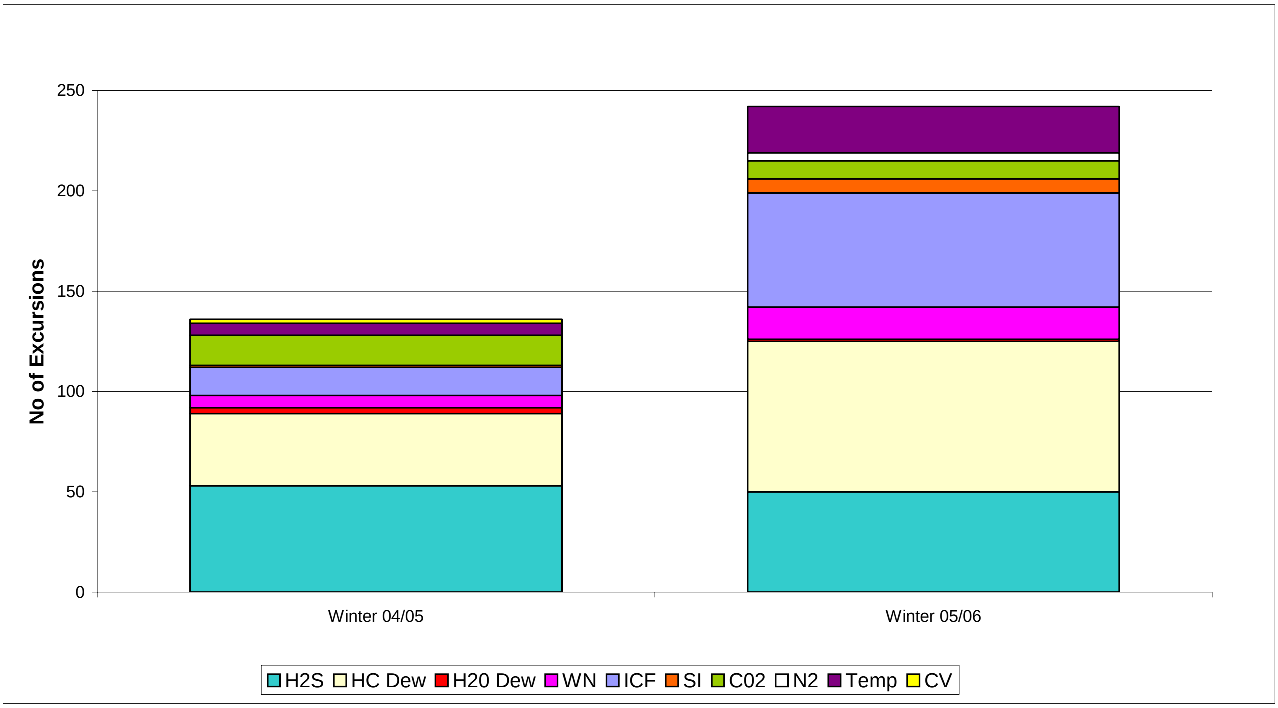


Figure A.16 shows the number of occasions over winter 2005/06 where gas entering the NTS has been outside of entry specification. The number of excursions nearly doubled on the previous year, with particularly high increases in those related to high hydrocarbon content and incomplete combustion factor. Excursions lead to National Grid Gas NTS warning the operator to restore quality or reduce flows to prevent out of specification gas entering the NTS system and affecting supplies to consumers.

Figure A.16 – Gas Quality Excursions by Characteristic



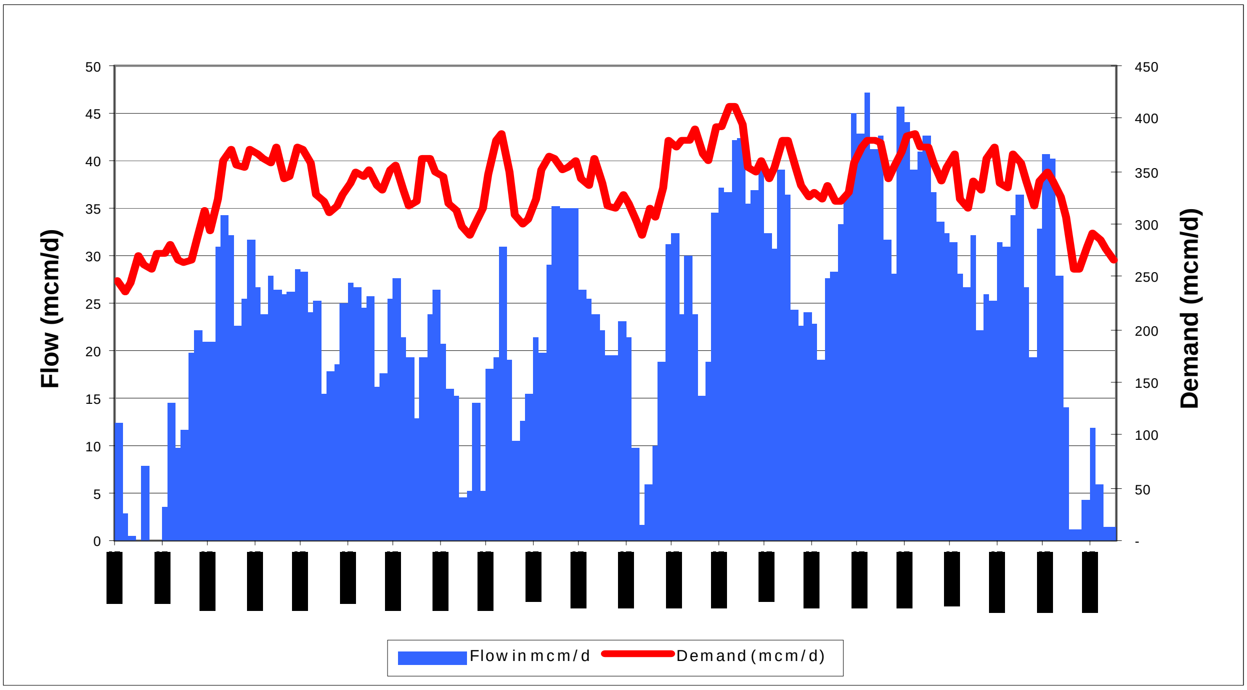
Interconnector Performance

Flows

The upgrade to the Belgian Interconnector from 8.5 to 16.5 bcm/y was commissioned on 8 November 2005. This additional capacity was first used on 16 November 2006 when flows reached 30.9 mcm/d. The peak Interconnector flow of 47.2 mcm was on 22 February 2006. Flows tended to be below expectations until mid January after which flows increased in line with expectations and full capacity was seen on a few days.

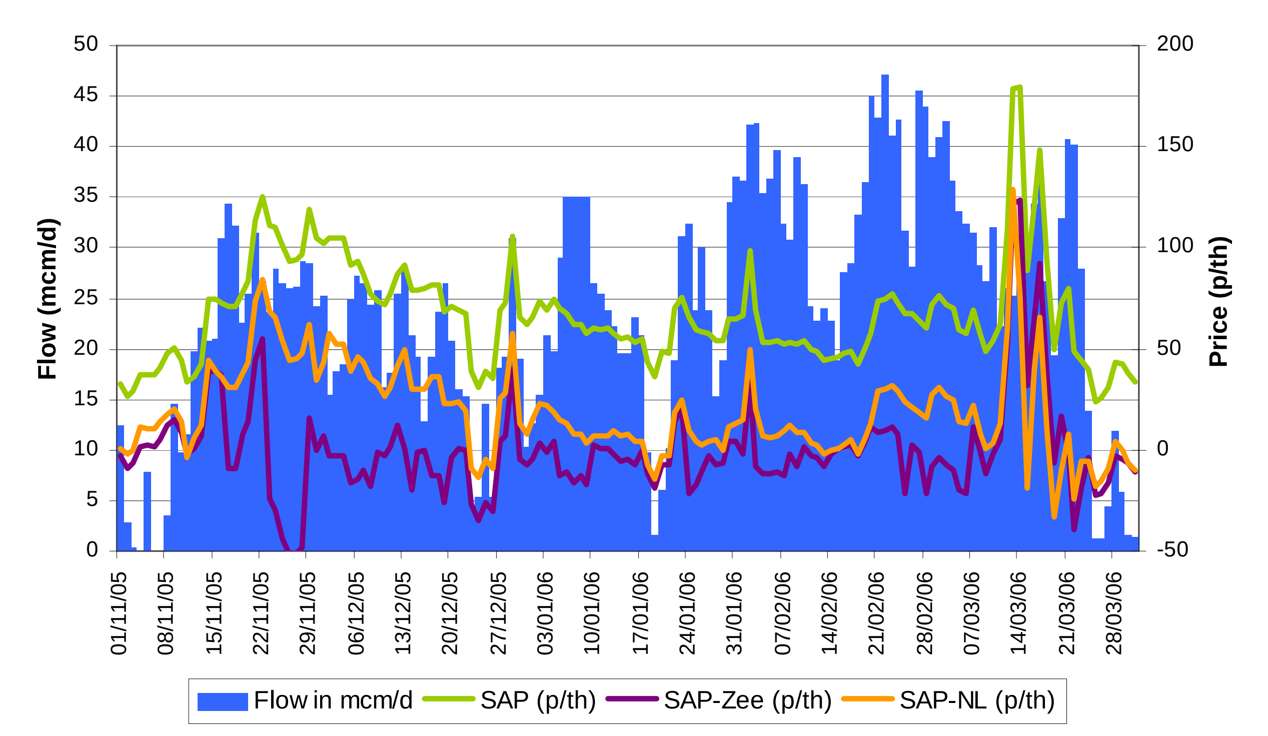
Figure A.17 compares Belgian Interconnector imports with demand. Figure A.18 compares Belgian Interconnector imports with the UK System Average Price (SAP), the differential between SAP and the Zeebrugge market price, and the differential between SAP and the Netherlands' TTF-Hi market prices[1]. The Zeebrugge day-ahead price and Netherlands TTF-Hi day-ahead price have been adjusted at the exchange rate on the gas flow day to pence per therm[2]. Note that where there was no trading on the relevant exchange, the previous day's price is used. Also the UK price is an end of day price, as opposed to a day-ahead price, and will therefore tend to be more volatile.

Figure A.17 – Interconnector Flows vs Demand



[1] Source - APX
[2] Source - Bank of England

Figure A.18 – Interconnector Flows vs GB and European Prices



As described in Chapter 1, peaks in flow tended to coincide with peaks in UK demand rather than peaks in price or price relative to Europe. For example the high demands on 18 November, 29 December, 2 February and 1 March coincided with peaks in Interconnector imports. Conversely, the high imports around 7 January and 8 February were at more modest prices whereas imports were below expectations during the high priced weeks beginning 21 November and 13 March. This reinforces concerns over the ability of shippers to source gas from Europe at short notice in response to un-forecast demand or high prices.

Zeebrugge gas prices generally tracked SAP throughout the winter. However, volumes on APX's Zeebrugge exchange were thin making it difficult to ascertain the true price. The closeness of the Zeebrugge price to SAP is indicative of spare capacity being available on the Interconnector.

The TTF-Hi price was generally below both Zeebrugge and UKP SAP throughout the winter period despite severe weather conditions in the Netherlands and elsewhere in Europe. TTF-Hi peaked on 30 November and 14-15 March, coincident with peaks in SAP, but generally remained flat and non-responsive to SAP price spikes. This indicates constrained capacity (whether physically or commercially) between Zeebrugge and the Netherlands.

Isle of Grain Performance

Flows

The Isle of Grain site, which is owned by Grain LNG, a subsidiary of National Grid, is the first modern Liquid Natural Gas (LNG) importation terminal in the country and heralds the return of large scale LNG importation into the UK for the first time in over 20 years. The facility has the capability to import and process 3.3 million tonnes per year, representing around four per cent of the UK's current annual gas demand.

BP/Sonatrach, who have acquired the current LNG capacity at Grain under a 20-year contract, determine actual LNG throughput. The terminal is used to berth and unload LNG ships, and process LNG prior to its re-gasification and nomination for delivery into the National Transmission System (NTS) and Southern Gas Networks.

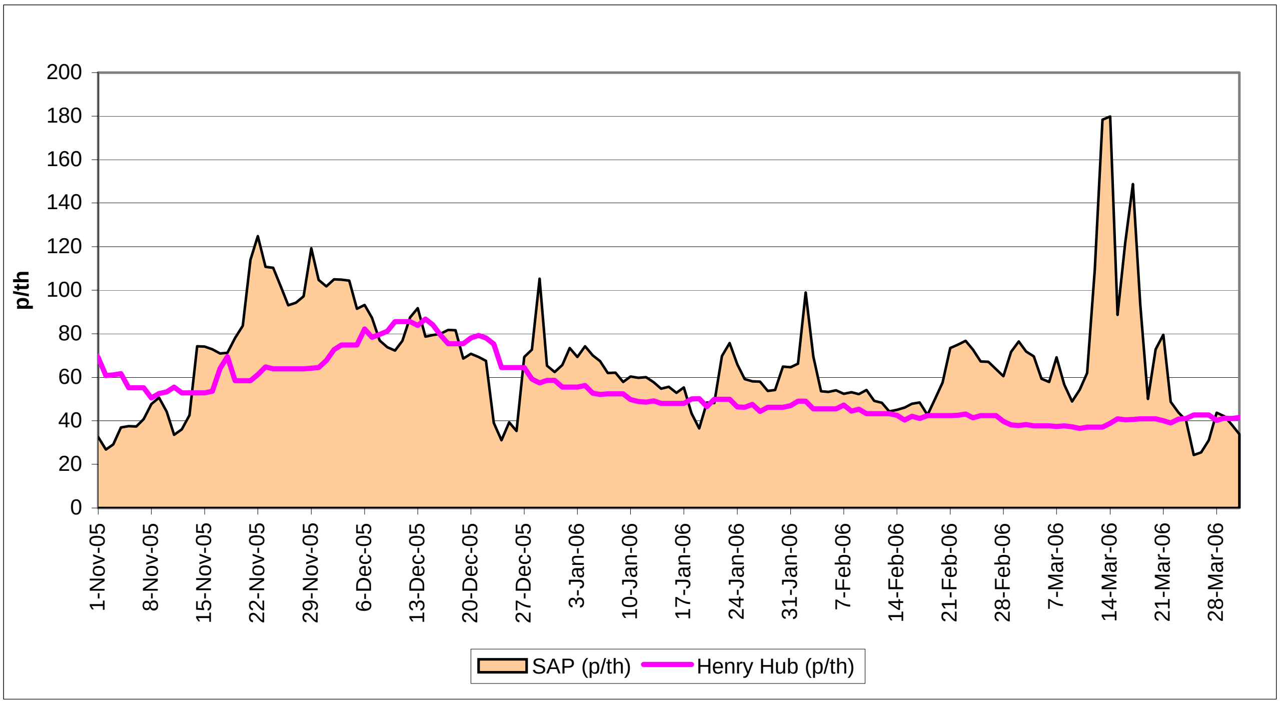
Isle of Grain flows were minimal during the low demand period before 19 November but then ramped up to contracted capacity by 8 December. Flows were then sporadic until mid-January, although demands were generally lower during this period. After mid-January, flows were close to contracted levels and rose to full capacity during the week beginning 27 February when cold weather compounded the Rough supply loss.

Spain introduced legislation early in the winter, which would penalise shippers for being out of balance (short) at 150% of the higher of SAP or the USA's Henry Hub price. In addition there were requirements for shippers to hold strategic stocks in Spanish LNG terminals and powers enabling LNG tankers to be chartered to standby offshore. Consequently, Spanish shippers were operating in a 'virtual' market at a premium to SAP throughout the winter and were incentivised to maintain consistent supplies of LNG.

Figure A.19 plots the UK System Average Price (SAP) against the USA's Henry Hub (HH) day-ahead price adjusted at the exchange rate on the gas flow day to pence per therm[3].

[3] Sources – APX, ICE, Bank of England

Figure A.19 – Winter Prices – 2005/06



Henry Hub (HH) began the winter higher than SAP, following the period of high prices after Hurricanes Katrina and Rita. HH reached a peak in mid December during a period of cold weather in the USA and ongoing concerns over gas supply. HH subsequently declined as the USA experienced a very mild winter and storage stocks rose well above average for the time of year[4].

Prior to mid November, flows from the Isle of Grain were very low and cargo deliveries were sporadic. This may reflect the price differential across the Atlantic with higher HH prices retaining the delivery of LNG cargoes.

However, SAP was higher than HH from mid November and flows at the Isle of Grain increased and cargo deliveries became more regular. 18 cargoes were observed from November to March arriving from Algeria, Egypt and Trinidad with most weekly berthing slots filled since the New Year[5]. In the USA, LNG cargo deliveries were fewer than the previous winter with only two cargoes delivered to the Lake Charles LNG terminal near Henry Hub and no deliveries to the new Gulf Gateway LNG terminal. The arrival of cargoes at Grain from Trinidad appears consistent with cargoes being diverted from the USA due to the GB price premium.

[4] Source – Energy Information Agency
[5] Source – Heren, LNG Grain Agency

Storage

<u>Patterns of use</u>

Figure 9 in Chapter 1 compares storage usage over winter 2005/06 against SAP and Figure A.26 below compares against demand.

Figure A.20 – Storage Usage vs Demand

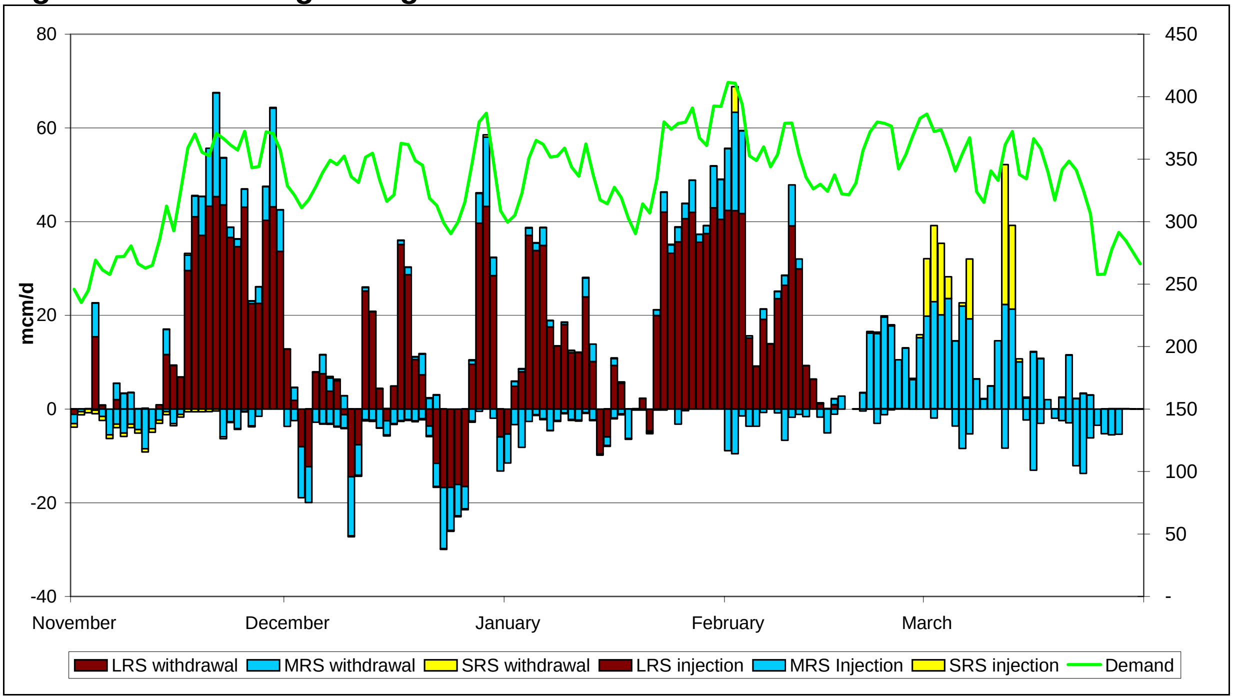


Table A.9 summarises withdrawals and injections over the winter. In December, Rough injected 133 mcm (1,440 GWh) and MRS injected 136 mcm (1,473 GWh).

Table A.9 – Storage Withdrawals and Injections in Winter 2005/06

	Withdrawals		Injection	
	MCM	GWh	MCM	GWh
LRS	1,795.25	19,448.54	159.98	1,731.2
MRS	709.63	7,687.66	411.38	4,456.62
SRS	127.02	1,376.05	23.19	251.23

Table A.10 shows the three highest days of storage withdrawal and Table A.11 shows the highest withdrawals for each type of storage.

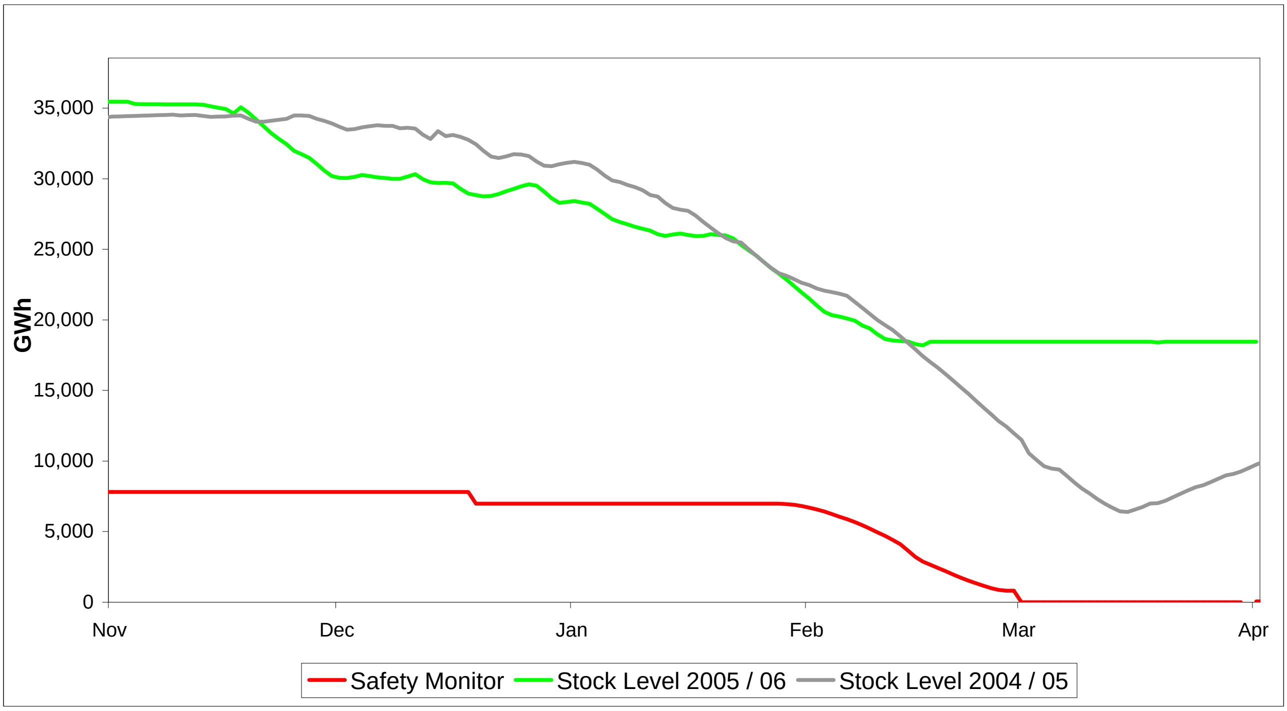
Table A.10 – Days of Highest Storage Withdrawal in Winter 2005/06

Date	LRS withdrawal (mcm/d)	MRS withdrawal (mcm/d)	SRS withdrawal (mcm/d)	Total (mcm/d)
2-Feb-06	42.34	20.98	5.45	68.77
21-Nov-05	45.35	22.09	0.09	67.53
29-Nov-05	43.16	21.04	0.17	64.37

Table A.11 - Highest Storage Withdrawals by Storage Type in Winter 2005/06

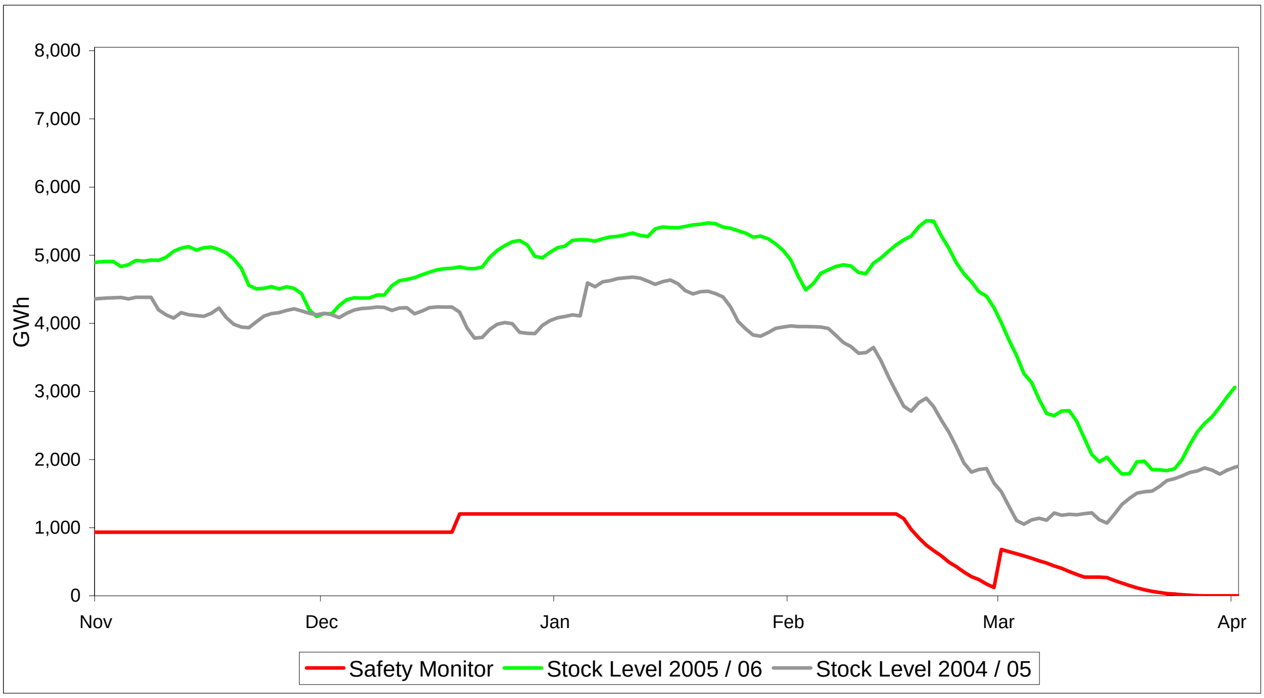
Storage type	Highest Withdrawal (mcm/d)	Date
LRS	45.35	21/11/05
MRS	23.53	04/03/05
SRS	29.86	12/03/06

Figure A.21– Long Range Storage



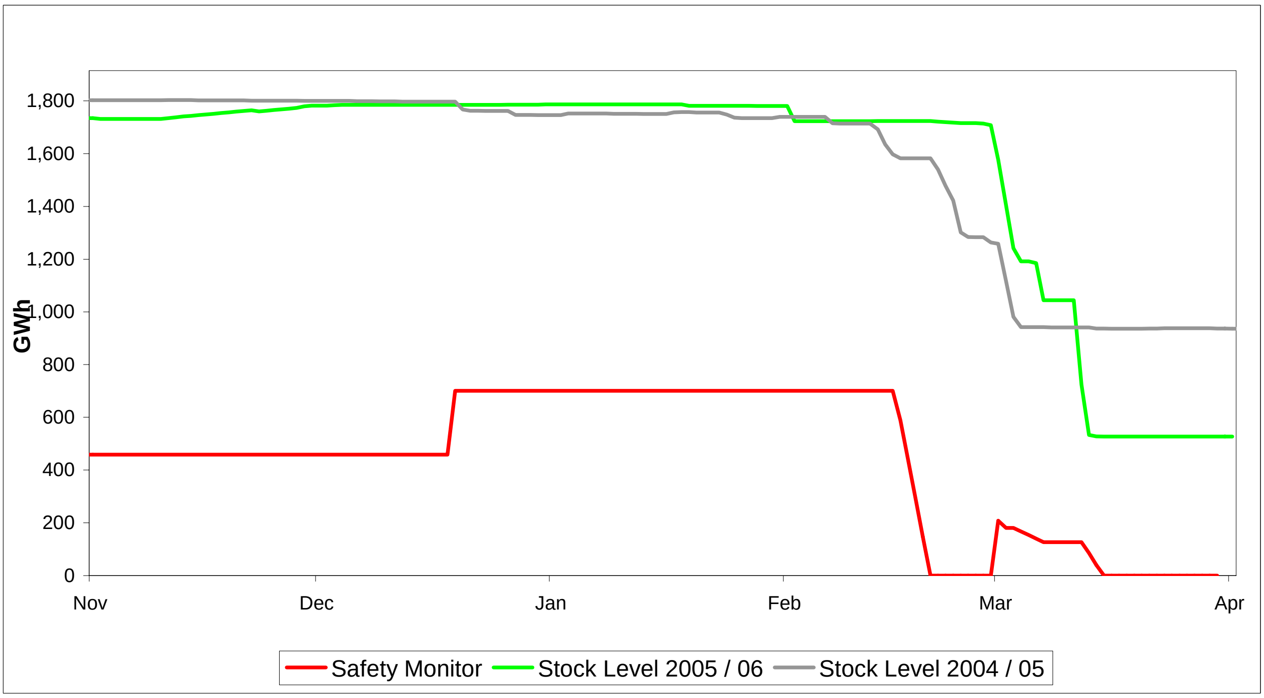
Rough started the winter period with a slightly higher stock position than the previous winter and there was little opportunity to refill during November. However, slightly milder temperatures in December mean that limited injection was possible. The incident at Rough on 16 February 2006 meant that injection and withdrawal was curtailed for the remainder of the winter period.

Figure A.22 – Medium Range Storage



Opening stock levels for MRS were higher this winter than for 2004/05. Additional capacity was commissioned at Humbly Grove in November but this limited its opportunity for injection prior to the winter period. However, slightly milder temperatures in December mean that some injection was possible.

Figure A.23 – Short Range Storage



SRS stock levels remained broadly similar in 2005/06 to the previous winter. However, in early March 2006, there was significant use of SRS to support demands generated by colder weather and the loss of the Rough Storage Platform.

Storage use and price

High demands in late November coincided with system prices up to £1.25/th and significant periods of withdrawal from MRS. However there were no SRS withdrawals other than boil off and use for the Scottish Independent Undertakings.

There were further periods of high demand on 29 December and 2 February coinciding with system prices of £1.05/th and 99p/th. These led to significant MRS withdrawal and small SRS withdrawals suggesting that SRS usage was determining marginal prices or that prices were high enough to trigger the release of SRS.

However, the extensive use of MRS and SRS from mid February following the loss of Rough led to more modest increases in SAP (77p/th) until mid March when SRS stocks became depleted and prices rose to £1.80/th.

Operating margins

There was one withdrawal of operating margins gas from storage. 4,722,222 kWh (0.46 mcm) was withdrawn from Dynevor Arms on 29 December 2005 due to supply losses and NTS compressor problems.

Further Analysis of 2005/06 – Electricity

Weekly Demand & Generation Availability

Figure A.24 shows the weekly peak demands, both actual and normal. This shows higher than normal demands in late November, reflecting the cold weather spell and the highest demand value for the whole winter, while higher than normal demands in March again consistent with a cold weather spell. As reported in Chapter 2, the demand peak was in late November (29 Nov) at 60.3 GW.

Figure A.24 – Weekly Peak Demand, Actual and Normal

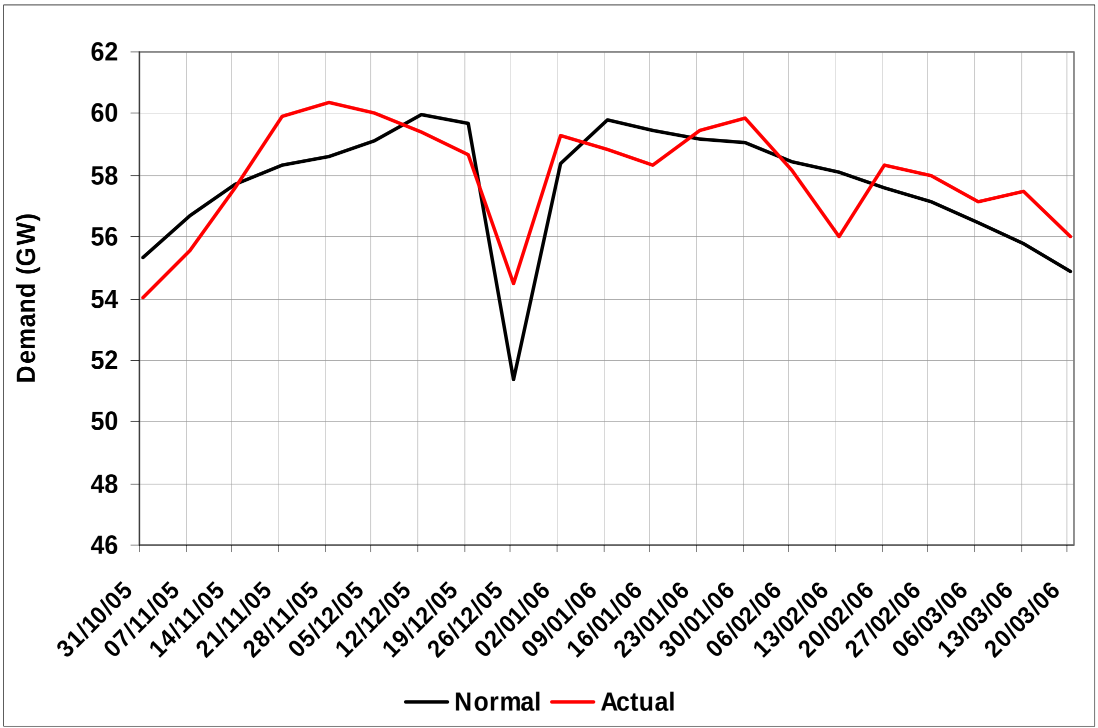


Figure A.25 compares the peak-of-week generation availability declared to National Grid in real time, along with declared UK-France Interconnector output against outturn demand and Short-Term Operating Reserve Requirement (STORR)[6]. This demonstrates that the times when electricity plant margins were particularly tight were on 29 December 2005, the day that a High Risk of Demand Reduction (HRDR) was issued, and 13 March 2006, the day of the Gas Balancing Alert.

[6] Short-Term Operating Reserve Requirement is based on assumed Standing Reserve (including Supplement Standing Reserve) availability, required headroom within the Balancing Mechanism (Regulating Reserve) and Frequency Reserve required net of contracted Response. Contracted Non-BM Standing Reserve availability has been also been netted off STORR.

Figure A.25 - On-The-Day Generation Availability and Demand

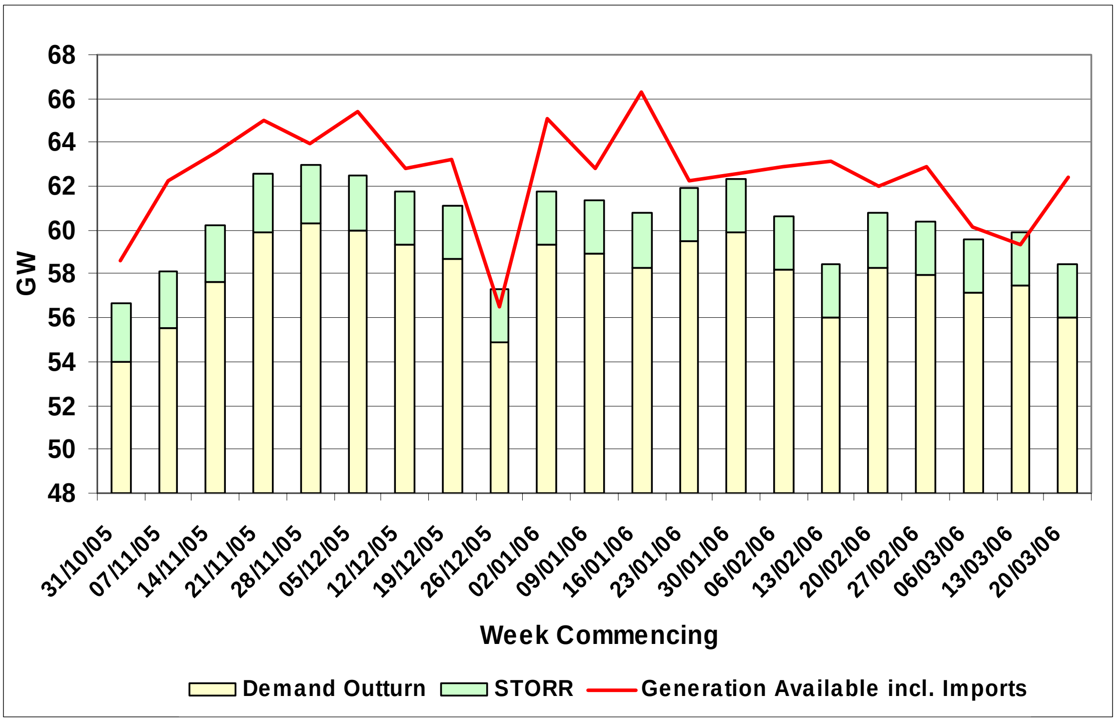


Table A.12 shows the Notices of Insufficient Margin (NISM) and the HRDR issued between November '05 and March '06. The number of NISMs was typical of recent winters.

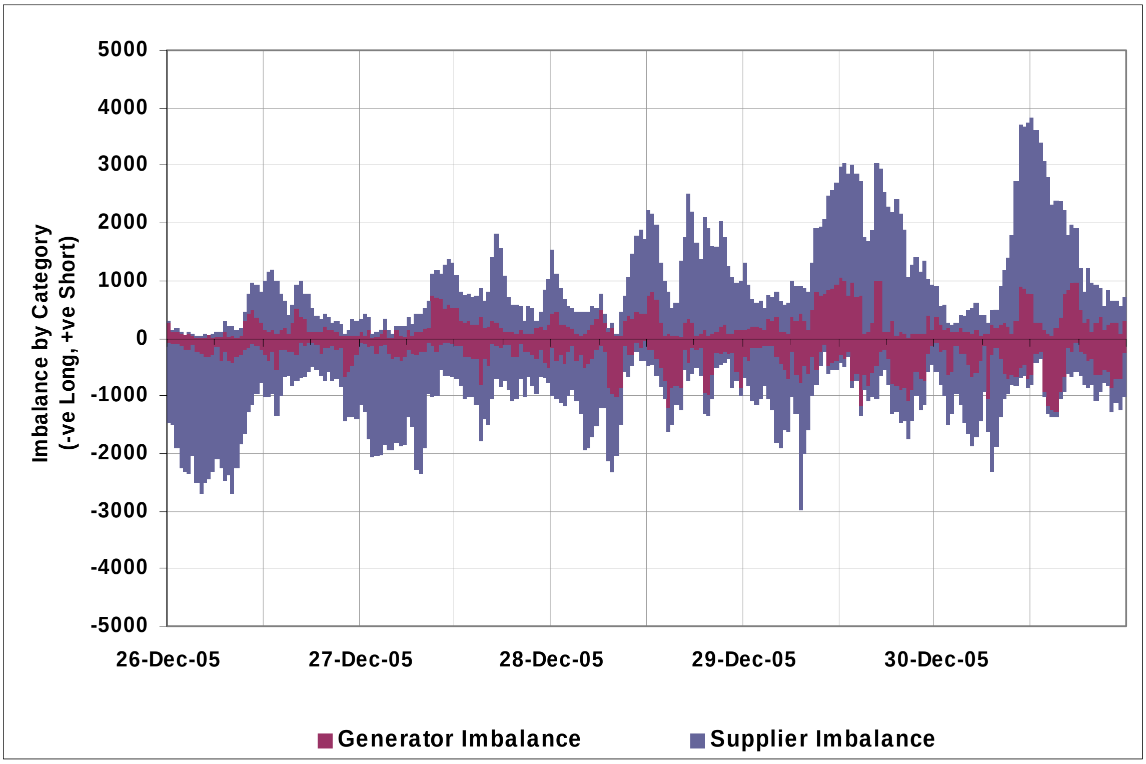
Table A.12 - Issued System Warnings for Margin Shortfalls

Issue Type:	Margin Shortfall Period	Shortfall Range	First Issued	Cancelled
NISM	14/11/2005 16:30 – 14/11/2005 18:30	300 - 500	14/11/2005 10:00	14/11/2005 16:00
NISM	24/11/2005 16:30 – 24/11/2005 18:30	200 - 2000	24/11/2005 05:15	24/11/2005 19:00
HRDR/NISM	29/12/2005 16:30 – 29/12/2005 18:30	1300 - 1800	28/12/2005 20:35	29/12/2005 18:00
NISM	13/03/2006 17:00 – 13/03/2006 19:00	600 - 1500	12/03/2006 23:00	13/03/2006 12:00

The HRDR on the 29 December 2005 was, of course, issued during the Christmas period; a time associated with lower than normal demands. A possible explanation of the HRDR is a lack of market reaction during cold weather spells in the holiday period. The HRDR was issued as the level of declared generator availability did not meet forecast demand. The HRDR was not cancelled until after the affected period.

Figure A.26 shows the breakdown of half-hourly imbalance, during the week in which the HRDR was issued (week commencing 26 December 2005), for both suppliers and generators. This indicates that the main driver of the lack of declared generator availability and subsequent issue of an HRDR was suppliers not contracting fully for the amount of demand on the system, and hence a lack of available generation as a result. It is clearly important that the market reacts to appropriate market signals, to ensure that declared availability will meet demand.

Figure A.26 - Categorised Half-Hourly Imbalance, w/c 26th December 2005



Generation Supply Build–Up

Table A.13 shows the percentage of availability by fuel type delivered in winter 2005/06 and a comparison with our winter 2005/06 assumptions as commented on in Chapter 2.

Table A.14 shows the percentage of generation by fuel type delivered in winter 2005/06. Comparing Tables A.13 and A.14, it can be seen that coal-fired stations did not run at maximum availability throughout the winter. Outturn availability was 84%, although actual generation as a percentage of maximum availability was 77%. This suggests that there is more scope for coal-fired stations to run baseload and deliver further gas relief from the electricity market.

Comparing Tables A.13 and A.14, it can be seen that gas availability was at 74%, yet actual gas-fired generation as a percentage of maximum availability was 48%, implying that gas-fired stations ran around 65% of the time they were available. Given coal-fired stations ran around 91% of the time they were available, this further supports the argument that gas plant was marginal.

Table A.13 - Actual Declared Availability as a Percentage of Maximum Availability

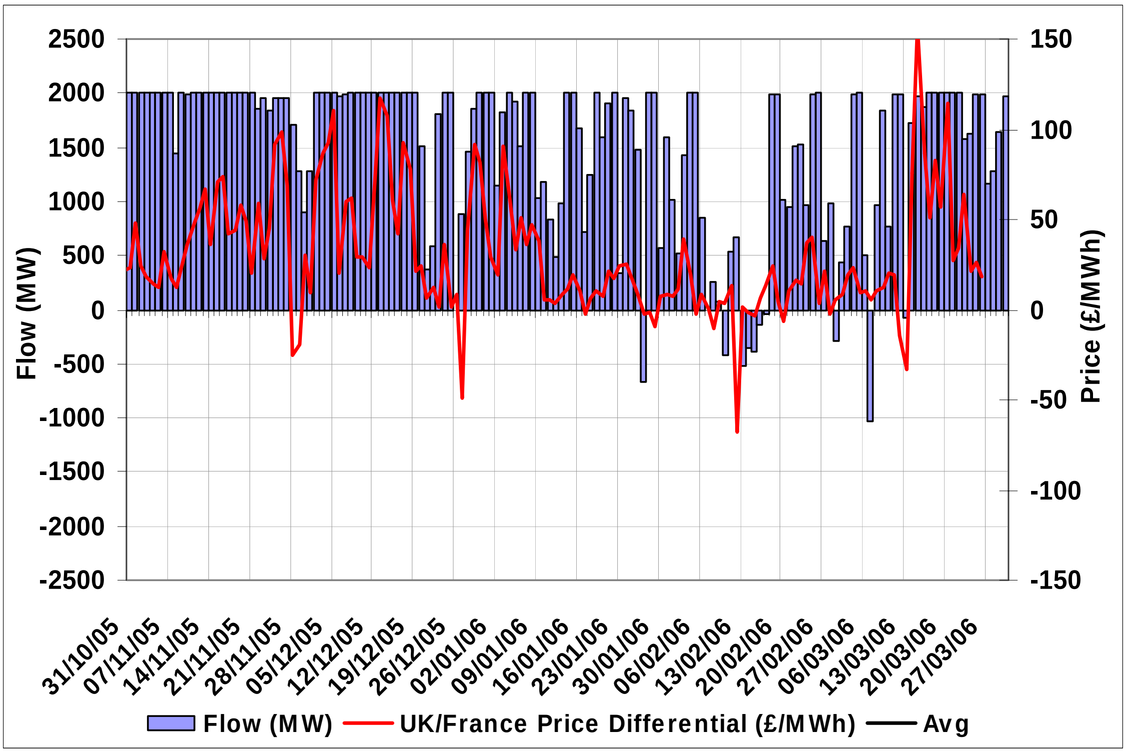
Fuel Type	Nov-05 to Mar-06	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	WOR 2005/6 Assumption
CCGT	74%	79%	72%	73%	74%	70%	95%
COAL	84%	81%	85%	86%	84%	85%	85%
NUCLEAR	78%	71%	76%	83%	81%	82%	95%
OCGT	93%	93%	93%	94%	93%	89%	95%
OIL	50%	53%	45%	50%	53%	51%	95%
OTHER	70%	62%	64%	71%	79%	74%	50%
PUMPED STORAGE	96%	87%	100%	100%	99%	96%	100%

Table A.14 Actual Generation Data as percentage of Maximum Availability

Fuel Type	Nov-05 to Mar-06	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06
CCGT	48%	53%	45%	48%	49%	44%
COAL	77%	69%	79%	78%	78%	81%
NUCLEAR	78%	70%	76%	81%	81%	81%
OCGT	2%	2%	2%	2%	2%	3%
OIL	13%	9%	8%	11%	21%	20%
OTHER	33%	41%	30%	31%	35%	28%
PUMPED STORAGE	17%	16%	18%	17%	16%	18%

Figure A.27 shows UK-France Interconnector flows and UK-France price differential for demand peak times (15:00 – 19:00). This shows how, during the winter, the UK-France Interconnector will sometimes send power to the UK over the daily demand peak even where price differentials are negative (French power price above UK power price). During the November and March cold spells the power came into the UK across this Interconnector consistent with a high UK to France price differential.

Figure A.27 – Daily UK-France Interconnector Flow and Price Differential



The Northern Ireland to Scotland Interconnector was consistently flowing out to Northern Ireland from the Scotland throughout the day with flows varying between 0.15 GW and 0.3 GW.

Prices

Day-ahead baseload electricity prices rose from £33/MWh at the beginning of September 2005, creeping up to around £44/MWh by the first week of October. Prices remained fairly flat until spikes in mid-November and late-November, reaching £111/MWh, for the day which the electricity demand outturn was the winter 2005/06 high.

December prices were volatile, and throughout January and February prices were relatively low during mild spells of weather, where baseload price varied between £40/MWh and £70/MWh. Following the fire at Rough gas-storage facility and cold weather, baseload price rose significantly peaking at £141/MWh, the winter high.

Prices during the issued HRDR were comparatively low with baseload price at £70/MWh for the 29 December 2005.

Despite the attractive prices, the level of estimated customer demand management saw no growth.

Figure A.28 – Day-ahead Electricity Prices

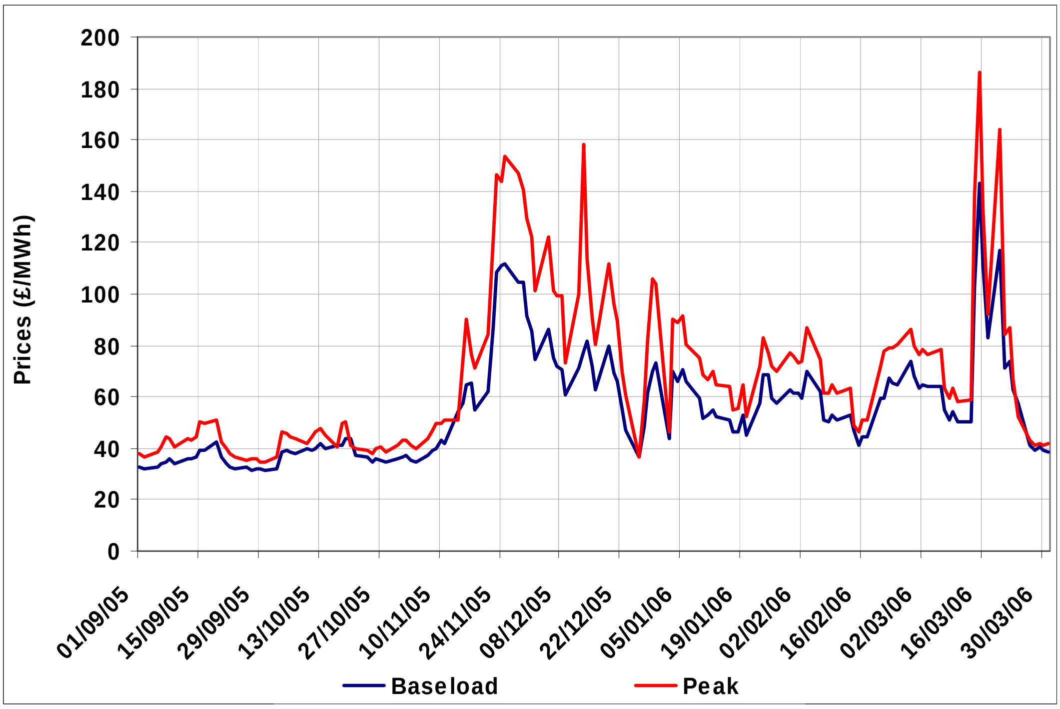
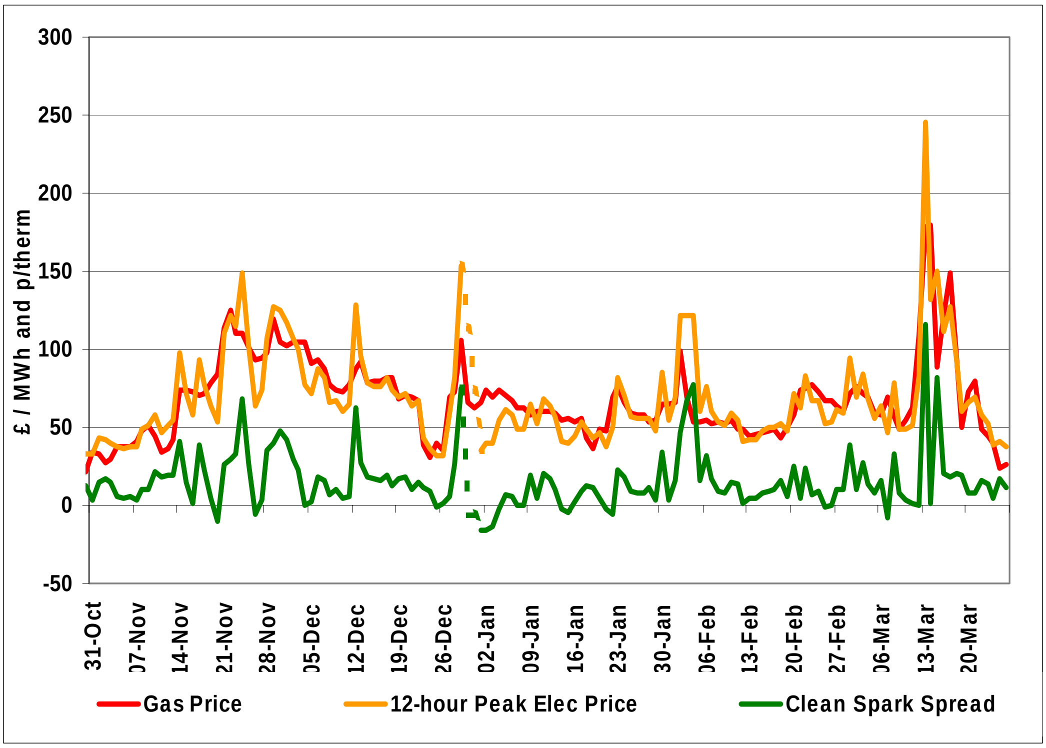


Figure A.29 shows the gas and electricity within day prices and clean spark spread prices. Clean spark spread is the spark spread reflecting the cost of CO_2 allowance.

Figure A.29 - Gas, Electricity & Clean Spark Spread, winter 2005/06



Annex B - Preliminary 2006/07 Load Duration Curves

The following table provides the demand data used in the Load Duration Curves in Figures 17,18 and 19 in Chapter 3. It should be noted that this data is based on National Grid's 2005 demand forecasts and hence is subject to update once the 2006 demand forecasts are completed. It should also be noted that the demand response data for CCGTs and Industrial and Commercial loads is based on typical levels observed in 2005/06, and is independent of day number; that is, no attempt has been made to simulate the affect of weather on daily demand response levels.

Table B.1 - Demand data for Figs 17, 18 and 19

All data in mcm/d

	Average					1 in 10					1 in 50				
Day no.	Domestic	Other NDM	DM - 2005/06 DR	2005/06 CCGT DR	2005/06 I & C DR	Domestic	Other NDM	DM - 2005/06 DR	2005/06 CCGT DR	2005/06 I & C DR	Domestic	Other NDM	DM - 2005/06 DR	2005/06 CCGT DR	2005/06 I & C DR
1	269	90	118	20	7	294	97	123	20	7	317	103	126	20	7
2	246	84	117	20	7	288	95	122	20	7	307	101	124	20	7
3	238	81	117	20	7	282	94	122	20	7	299	98	123	20	7
4	233	80	116	20	7	277	93	121	20	7	293	97	122	20	7
5	229	79	116	20	7	273	91	120	20	7	288	96	122	20	7
6	226	78	115	20	7	269	90	120	20	7	284	94	121	20	7
7	223	78	115	20	7	266	89	119	20	7	281	94	121	20	7
8	222	77	115	20	7	263	89	119	20	7	279	93	121	20	7
9	220	77	115	20	7	260	88	118	20	7	277	92	120	20	7
10	219	77	115	20	7	258	87	117	20	7	275	92	120	20	7
11	217	76	114	20	7	257	87	116	20	7	273	91	120	20	7
12	216	76	114	20	7	255	86	115	20	7	271	91	119	20	7
13	214	75	114	20	7	253	86	115	20	7	269	90	119	20	7
14	213	75	114	20	7	251	85	114	20	7	268	90	119	20	
15	212	74	114	20	7	249	85	114	20	7	266	89	118	20	7
16	210	74	114	20	7	248	84	114	20	7	265	89	118	20	7
17	209	73	114	20	7	246	84	114	20	7	263	88	118	20	7
18	208	73	114	20	7	244	83	114	20	7	262	88	118	20	7
19	206	72	114	20	7	243	83	113	20	7	261	87	117	20	7
20	205	72	113	20	7	241	82	113	20	7	260	87	117	20	7
21	204	71	113	20	7	240	82	113	20	7	258	86	117	20	7
22	203	71	113	20	7	239	81	113	20	7	257	86	117	20	7
23	203	71	113	20	7	237	81	113	20	7	256	85	116	20	7
24	202	71	113	20	7	236	80	113	20	7	255	85	116	20	7
25	202	71	113	20	7	235	80	112	20	7	254	85	116	20	7
26	201	70	113	20	7	234	80	112	20	7	252	84	116	20	7
27	200	70	113	20	7	233	79	112	20	7	251	84	116	20	7
28	200	70	112	20	7	231	79	112	20	7	250	83	116	20	7
29	199	70	112	20	7	230	78	112	20	7	249	83	115	20	7
30	198	69	112	20	7	229	78	112	20	7	248	83	115	20	7
31	198	69	112	20	7	228	78	112	20	7	247	82	115	20	7
32	197	69	112	20	7	227	77	112	20	7	246	82	115	20	7
33	197	68	112	20	7	226	77	112	20	7	246	81	115	20	7
34	196	68	112	20	7	226	77	112	20	7	245	81	115	20	7
35	196	68	112	20	7	225	76	112	20	7	244	80	115	20	7
36	195	67	112	20	7	224	76	112	20	7	243	80	114	20	7
37	195	67	112	20	7	223	76	112	20	7	242	79	114	20	7
38	194	67	112	20	7	222	75	112	20	7	241	79	114	20	7
39	193	66	112	20	7	221	75	111	20	7	240	78	114	20	7
40	193	66	112	20	7	221	75	111	20	7	240	78	114	20	7
41	192	66	112	20	7	220	74	111	20	7	239	77	114	20	7
42	192	65	111	20	7	219	74	111	20	7	238	77	114	20	7
43	191	65	111	20	7	218	74	111	20	7	237	76	114	20	7
44	191	65	111	20	7	217	73	111	20	7	236	76	113	20	7
45	190	65	111	20	7	216	73	111	20	7	235	76	113	20	7
46	189	64	111	20	7	216	73	111	20	7	234	75	112	20	7
47	189	64	111	20	7	215	72	111	20	7	233	75	112	20	7
48	188	64	111	20	7	214	72	111	20	7	231	74	112	20	7
49	187	64	111	20	7	213	72	111	20	7	230	73	112	20	7
50	187	63	111	20	7	212	72	111	20	7	228	73	113	20	7

Day no.	Average					1 in 10					1 in 50				
	Domestic	Other NDM	DM - 2005/06 DR	2005/06 CCGT DR	2005/06 I & C DR	Domestic	Other NDM	DM - 2005/06 DR	2005/06 CCGT DR	2005/06 I & C DR	Domestic	Other NDM	DM - 2005/06 DR	2005/06 CCGT DR	2005/06 I & C DR
51	186	63	111	20	7	211	71	110	20	7	227	73	112	20	7
52	186	63	111	20	7	210	71	110	20	7	226	72	112	20	7
53	185	62	111	20	7	210	71	110	20	7	225	72	112	20	7
54	184	62	111	20	7	209	70	110	20	7	224	71	112	20	7
55	184	62	111	20	7	208	70	110	20	7	223	71	112	20	7
56	183	62	111	20	7	207	70	110	20	7	222	71	112	20	7
57	183	61	110	20	7	207	69	110	20	7	221	70	112	20	7
58	182	61	110	20	7	206	69	110	20	7	220	70	112	20	7
59	181	61	110	20	7	205	69	110	20	7	219	70	112	20	7
60	181	61	110	20	7	204	69	110	20	7	218	69	112	20	7
61	180	60	110	20	7	204	68	110	20	7	217	69	111	20	7
62	179	60	110	20	7	203	68	110	20	7	216	68	111	20	7
63	179	60	110	20	7	202	68	110	20	7	215	68	111	20	7
64	178	60	110	20	7	202	68	110	20	7	214	68	111	20	7
65	177	59	110	20	7	201	67	110	20	7	213	68	111	20	7
66	177	59	110	20	7	200	67	110	20	7	212	67	111	20	7
67	176	59	110	20	7	199	67	110	20	7	210	67	111	20	7
68	176	59	110	20	7	199	67	109	20	7	210	66	111	20	7
69	175	58	110	20	7	198	66	109	20	7	209	66	111	20	7
70	174	58	109	20	7	197	66	109	20	7	208	66	111	20	7
71	174	58	109	20	7	197	66	109	20	7	207	66	111	20	7
72	173	58	109	20	7	196	66	109	20	7	206	66	111	20	7
73	173	58	109	20	7	195	65	109	20	7	205	65	111	20	7
74	172	58	109	20	7	194	65	109	20	7	204	65	111	20	7
75	172	57	109	20	7	194	65	109	20	7	203	65	111	20	7
76	171	57	109	20	7	193	65	109	20	7	203	65	111	20	7
77	171	57	109	20	7	192	64	109	20	7	202	65	111	20	7
78	170	57	109	20	7	192	64	109	20	7	201	64	110	20	7
79	170	57	109	20	7	191	64	109	20	7	200	64	110	20	7
80	169	56	109	20	7	190	64	109	20	7	199	64	110	20	7
81	169	56	109	20	7	189	63	109	20	7	198	64	110	20	7
82	168	56	109	20	7	189	63	109	20	7	197	63	110	20	7
83	168	56	109	20	7	188	63	109	20	7	197	63	110	20	7
84	167	56	109	20	7	187	63	108	20	7	196	63	110	20	7
85	167	56	109	20	7	187	62	108	20	7	195	63	110	20	7
86	166	55	108	20	7	186	62	108	20	7	194	63	110	20	7
87	166	55	108	20	7	185	62	108	20	7	193	62	110	20	7
88	165	55	108	20	7	184	61	108	20	7	192	62	110	20	7
89	165	55	108	20	7	184	61	108	20	7	191	62	110	20	7
90	165	55	108	20	7	183	61	108	20	7	191	62	110	20	7
91	164	54	108	20	7	182	61	108	20	7	190	61	109	20	7
92	164	54	108	20	7	182	60	108	20	7	189	61	109	20	7
93	163	54	108	20	7	181	60	108	20	7	188	61	109	20	7
94	163	54	108	20	7	180	60	108	20	7	187	61	109	20	7
95	162	54	108	20	7	179	60	108	20	7	186	60	109	20	7
96	162	54	108	20	7	179	59	108	20	7	186	60	109	20	7
97	161	53	108	20	7	178	59	108	20	7	185	60	109	20	7
98	161	53	108	20	7	177	59	108	20	7	184	60	109	20	7
99	160	53	108	20	7	177	59	108	20	7	183	60	109	20	7
100	160	53	108	20	7	176	58	107	20	7	182	59	109	20	7

Annex C - Overview of Safety Monitors

This Annex explains the concept of safety monitors: what they are and how they are operated, both in general and with specific reference to the 2005/06 winter. For a more detailed explanation of the methodology used to calculate the monitors see our web site document 'Safety and Firm Gas Monitor Methodology'[7].

What are Safety Monitors?

Safety monitors were introduced in 2004 to replace the so-called 'Top-up' monitors, which had existed through the Network Code since 1996. The purpose of the Top-up arrangements was to underpin security of supply to firm customers. It did this by ensuring that sufficient volumes of gas were retained in storage throughout the winter, consistent with 1 in 50 weather demand levels. If necessary, Transco would buy gas to put in storage in order to ensure that Top-up levels were maintained.

In common with Top-up, the safety monitors define levels of storage that must be maintained through the winter period. However, as the name suggests, the focus of the safety monitors is public safety rather than security of supply. It is a requirement of National Grid Gas' safety case that we operate this monitor system and that we take action to ensure that storage stocks do not fall below the defined levels.

The levels of storage established by the safety monitors are those required to ensure an adequate pressure can be maintained in the network at all times and thereby protect public safety. They ensure the preservation of supplies to domestic customers, other non-daily metered customers and certain other customers who could not safely be isolated from the gas system if necessary in order to achieve a supply-demand balance.

There are three safety monitors: one for long-range storage (Rough); one for mid-range storage (Hornsea, Hatfield Moor, Hole House Farm and Humbly Grove combined); and one for short-range storage (Avonmouth, Dynevor Arms, Glenmavis and Partington combined).

How are the Safety Monitors Operated?

Each of the monitors has an initial level, which defines the level of gas that must be in the relevant storage facilities at the start of the winter. These levels reduce as the winter proceeds, reflecting the fact that less gas is required in store towards the end of the winter than at the start. The curve of the monitor level through the winter is known as the monitor profile (see Figure C.1).

The monitor profiles are calculated and published prior to the start of the winter. To calculate them, we have to make a number of assumptions relating to the supply and demand for gas over the winter period. We keep these assumptions under review throughout the winter, and we may amend the monitors given new information.

National Grid monitors the level of gas in each of the three storage facility types throughout the winter to ensure that the actual stock level does not fall below the relevant monitor level. If this were to occur, there would be insufficient gas left in storage to ensure an

[7] http://www.nationalgrid.com/uk/Gas/Data/misc/

adequate pressure can be maintained in the network at all times and thereby protect public safety. We would therefore be obliged by our safety case to take action to remedy this situation.

In the lead-up to such a situation, National Grid would advise the market with the objective of encouraging mitigating action. If necessary, however, the Network Emergency Co-ordinator (NEC) may require the relevant storage operators to reduce or curtail flows of gas out of storage. If the NEC is called upon, there is a duty on all market participants to cooperate with the NEC who has a responsibility to take action to prevent as far as possible a supply emergency developing.

We would continue to provide information to the market as the situation developed. While National Grid would seek to minimise the extent of any intervention in the market, the balance between allowing the market to resolve the situation and taking action via the NEC will clearly depend on the severity of the situation and the associated timescales.

Safety Monitor Operation in 2005/06 Winter

The 2005/06 safety monitors were set prior to the start of the winter, based upon the expected availability of non-storage supplies (beach gas plus imports through the Belgian Interconnector and Grain LNG). Actual deliveries were closely monitored and used to inform two subsequent revisions to the safety monitors on 20 December and 2 March. Table C.1 describes the expected supplies underlying the safety monitors. Only 75% of the delivery capability of Humbly Grove and the enhancement to the Hole House Farm were included due to uncertainty over the availability of these new facilities.

Initially there was considerable uncertainty associated with the supply side position, most notably the impact of Hurricanes Katrina and Rita on the delivery of LNG to Europe. Consequently an additional volume was included in the Long Range Monitor to cover a 10 mcm/d loss of supply across the winter. The average beach figure was based upon 92.5% of an expected maximum beach availability of 327 mcm/d.

Table C.1 – 2005/06 Safety Monitor Assumptions

mcm/d	Initial	20 Dec 2005	2 March 2005
Average Beach	303		
Average Interconnector	42		
Average Isle of Grain	13		
Total non-storage	358	348	348
Storage	111	111	69
Supply risk allowance	-10		
Total	459	459	417

Table C.2 shows the initial and revised monitor levels, and Figure C.1 plots the monitor levels across the winter, showing the revisions on 20 December and 2 March, and the decline of the monitor profiles in the latter part of the winter.

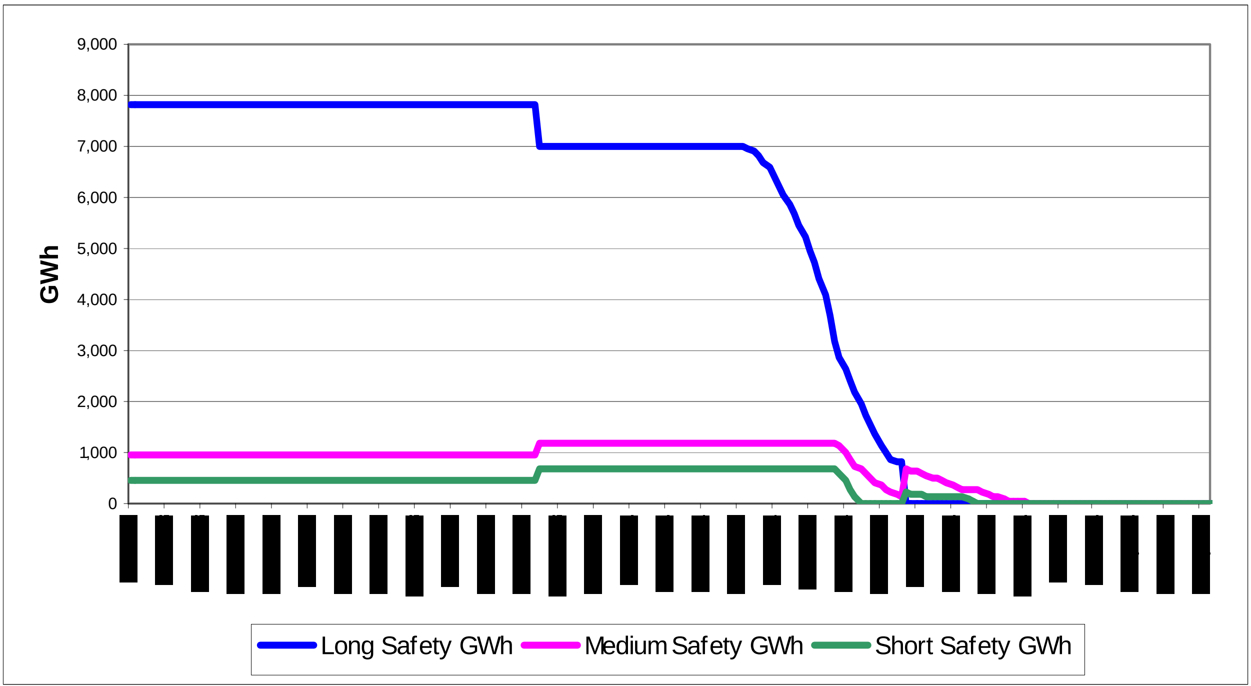
The revision on 20 December was largely driven by a re-assessment of expected Interconnector flows over the remaining part of the winter. This led to a re-allocation of the 10 mcm/d supply risk allowance across the various safety monitors.

The revision on 2 March followed the Rough outage on 16 February, with the remaining long duration safety monitor being reallocated across the short and medium duration monitors.

Table C.2 – Initial and Revised Safety Monitor Levels

	LRS Safety Monitor (GWh)	LRS Safety Monitor (%)	MRS Safety Monitor (GWh)	MRS Safety Monitor (%)	SRS Safety Monitor (GWh)	SRS Safety Monitor (%)
1-Oct-05	7,806	22.9%	933	12.7%	459	26.4%
20-Dec-05	6,987	20.5%	1,202	16.4%	700	40.2%
2-Mar-06	-	0.0%	681	9.3%	208	11.9%

Figure C.1 – 2005/06 Safety Monitor Development



Annex D - Overview of Gas Balancing Alerts

The concept of the Gas Balancing Alert (GBA) was introduced at the end of 2005 to alert the market at times when additional balancing actions might be needed. The GBA is activated when forecast demand (either "on-the-day" or "day-ahead") exceeds the GBA trigger level. The GBA trigger is the aggregate of expected supply availability, consistent with the assumptions used to calculate the storage safety monitors.

For non-storage gas supplies, the average supply assumptions are used. For storage gas supplies the full capability of each storage type (long, medium and short range) is used provided that:

a) there is sufficient gas in store to cover the various requirements of the Safety Monitors, Operating Margins and Scottish Independent Undertakings; and,
b) there is sufficient gas in storage to cover withdrawal for two days at maximum withdrawal rate.

Where a storage type does not have enough gas in store to cover these requirements then it is not included in the calculation of the GBA trigger.

Once a GBA is issued, it is for the market to respond with additional gas supplies and/or demand management in order to achieve balance. Lifting a GBA could lead to balancing actions being reversed thus re-triggering the GBA. Therefore, a GBA in respect of a particular gas day remains active for that day regardless of actions taken.

Post-GBA Multi-day Trades

After a GBA has been declared, National Grid NTS is able to accept Over-The-Counter (OTC) offers and offers placed for multiple and consecutive days. Multi-day offers can be made for a maximum of 7 days ahead from the date they are posted.

The derivation of System Average Price (SAP), whilst continuing to include all trades that are undertaken on the On-The-Day Commodity Market (OCM) for a gas day (except those relating to locational actions), will also include balancing actions undertaken by National Grid NTS through the acceptance of OTC offers. In addition, balancing actions taken on the OCM or OTC, including trades taken for more than one day, will set the SMPbuy and SMPsell.

Operation of the GBA Process in 2005/06 Winter

The initial supply assumptions for the 2005/06 winter are set out in Table D.1. Medium Range Storage availability at Humbly Grove and the enhancement to Hole House Farm were reduced by 25% to reflect the recent commissioning of these facilities.

Table D.1 – Initial 2005/06 Supply Assumptions for GBA Process

Mcm/d	Initial Supply Assumptions
Average Beach	303
Average Interconnector	42
Average Isle of Grain	13
Total non-storage	358
Long Range Storage	42
Medium Range Storage	28
Short Range Storage	49
Total Storage	119
Total Supply	477

Figure D.1 shows the GBA trigger, the day- ahead forecast at 1600hours and actual demands reconciled at D+5 over the winter period. The changes in trigger level are described in Table D.2.

Figure D.1 – 2005/06 GBA Triggers vs Demand

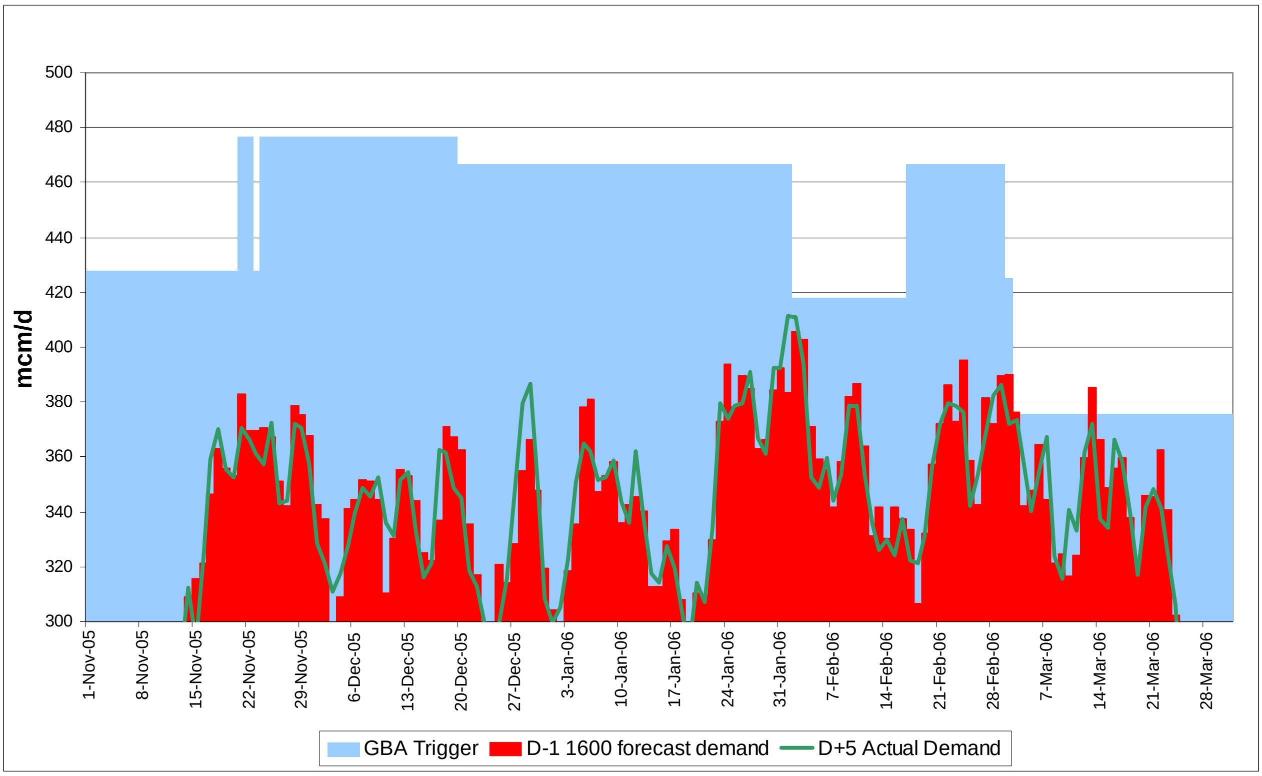


Table D.2– Changes to 2005/06 Trigger Levels

Date	Trigger Level	Note
1 Nov 2005	428	Short Range Storage still filling
21-24 Nov 2005	477	Short Range Storage above 2 day warning level
20 Dec 2005	467	Revision to non-storage supply assumptions
2 Feb 2006	418	Short Range Storage below 2 day warning level
17 Feb 2006	467	Short Range Storage above 2 day warning level as a result of falling monitor requirements
2 Mar 2006	425	Rough removed from supply assumption
3 Mar 2006	376	Short Range Storage below 2 day warning level

Actual demands remained below the GBA trigger throughout the winter. The day ahead forecast demand for Friday 3 March 2006 equalled the GBA trigger but this did not lead to an alert being issued.

The day ahead forecast for Monday 13 March 2006 exceeded the GBA trigger, which led to an alert being issued at 00:08 hours on 13 March 2006 following confirmation of the day ahead forecast demand of 385 mcm/d.

National Grid took no balancing actions and did not accept any single or multi- day offers in respect of the 13 March 2006. Actual demand on the 13 March 2006 was 372 mcm/d.

Annex E - Overview of Interruption Arrangements

This Annex provides further information on the arrangements under which Gas Transporters may interrupt certain large loads for capacity management purposes. For a precise understanding of these arrangements, the reader should refer to the relevant section of the Uniform Network Code (UNC).

Gas Transporters have rights under the UNC to interrupt Interruptible Supply Points (referred to here as "interruptible sites") in order to assist with the management of capacity on their networks. A site is eligible for interruptible status if it consumes at least 5,860,000 kWh (200,000 therms) per annum.

Gas Transporters' interruption rights are mirrored in the interruptible sites' contracts with their suppliers. We understand that the majority of such contracts only permit interruption where a Gas Transporter (National Grid Gas NTS or the relevant Distribution Network) has requested it. Some supply contracts, however, still permit interruption at the instigation of the supplier.

In return for being interruptible, the relevant shipper is not required to pay NTS (TO) Exit Capacity Charges or LDZ Capacity Charges. In addition, the shipper is entitled to a transportation charge credit if interruption is required at the interruptible site on more than 15 days in any price control formula year.

There are approximately 1400 interruptible sites. The great majority of these have interruptible arrangements that permit interruption for up to 45 days per annum. Twelve interruptible sites, known as TNIs, are interruptible for more than 45 days to reflect particular transportation constraints. Approximately 75 interruptible sites are known as Network Sensitive Loads (NSLs). NSLs have a higher probability of interruption as a result of their particular location on the gas transportation system.

Gas Transporters have licence obligations to develop their networks to provide capacity to meet anticipated 1 in 20 peak day demand, taking account of any interruption rights. Therefore an indication of the total level of capacity in the respective networks may be gained by examining the respective 1 in 20 peak day firm demand forecasts. The following table is an extract from the Gas Transportation Ten Year Statement 2005, Table A2.1C, showing the 2005 forecasts of 2006/07 1 in 20 peak day firm demand.

Table E.1 – Forecast 1 in 20 Peak Day Firm Demand by LDZ & NTS

NB demands in mcm/d have been estimated here by applying an assumed CV of 39 MJ/m3

LDZ	GWh/d	mcm/d
SC	349	32
NO	266	25
NW	551	51
NE	293	27
EM	479	44
WM	471	43
WA	242	22
EA	376	35
NT	517	48
SE	531	49
SO	390	36
SW	287	27
LDZ Total	4751	439
NTS Total	1328	123
Total	6079	561

Source: Gas Transportation Ten Year Statement 2005