NG's gas demand forecasting methodology

A FINAL REPORT FOR OFGEM

June 2006

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Executive summary

INTRODUCTION AND RECOMMENDATIONS

Ofgem has asked Frontier Economics to review the methodology underpinning the gas demand forecast employed by National Grid (NG) for the purpose of informing its Winter Outlook Report.

NG produces two types of gas demand forecast to inform its Winter Outlook Report:

- An annual gas demand forecast covering a 10 year period. This is made up of:
  - LDZ demand, which accounts for 65% of total annual throughput. This is split by NG into 4 load bands for the purposes of deriving the forecast. The lowest load band, corresponding to the domestic sector, accounts for around 60% of LDZ demand, with the industrial and commercial customers in the higher load bands accounting for around 40% of total LDZ throughput; and
  - NTS demand, which accounts for 35% of total annual throughput. NG groups these loads into three types for the purposes of forecasting: power generation, industrials and exports.
- Peak demand and load duration curve (LDC) forecasts. Having forecast the total annual gas demand, NG then profiles that demand to produce forecasts of peak demand and LDCs using historic daily load and weather information. Expected price levels do not currently play a role in this profiling exercise.

We make a number of recommendations about the way in which NG could improve its gas demand forecasting methodology throughout this report. In particular, we consider that NG should:

- consider moving from using annual data, to using quarterly data, in the regression analysis that it undertakes to estimate LDZ annual gas demand (Section 2.4);
- for the power generation sector this should include forward-looking simulations of expected gas peak demand by generators, rather than solely relying on a backward-looking modelling (Section 3.3),
- undertake scenario analysis to improve the modelling of net export flows, particularly so that an assessment can be made of the extent to which the UK can realistically depend on imports when demand is high (Section 3.3); and
- augment the daily demand forecasts with an analysis of demand response to different price levels by industrial customers and power generators (Section 4.2) a framework for which is provided in Section 5.

Within the rest of this Executive Summary we provide a brief overview of the key findings of our analysis.

FORECAST OF ANNUAL GAS DEMAND

LDZ demand

NG considers two different methodologies when forecasting gas demand for LDZs:

- an econometric modelling method which involves undertaking regression analysis of annual demand data over a period of years, and
- an "added load" method which considers likely additions and deductions to demand given changes to sources of demand such as new connections and efficiency improvements.

Forecasting performance

Table 1 reports the summary forecast performance of the LDZ model over the past 12 years to 04/05. This illustrates that the model performs relatively well, with the average absolute size of the forecasting error in any given year ranging from +/-1.2% one year-ahead, increasing to +/- 4% three years ahead. It should be noted, however, that one of the main reasons that the LDZ model performs reasonably well is due to the stability of the domestic load.

% Error	LDZ Annual
1-year ahead absolute error	1.18%
1-year ahead error over period	-0.06%
3-year ahead absolute error	4.41%
3-year ahead error over period	0.81%

Table 1: Summary forecast performance of the LDZ model

Source: NG

Note: A negative number implies an under-forecast

Main recommendations

The principle recommendation we make in respect of the LDZ modelling is that NG considers the potential benefits to be obtained by moving from annual to quarterly data in the regression analysis, which we believe to be threefold:

- improved robustness of the estimates;
- possibility to conduct model testing more reliably; and
- possibility to include more variables.

Forecast of annual NTS demand

Unlike the LDZ demand modelling, NTS demand is not modelled using regression analysis, but is instead modelled through simulations of expected future demand. The inputs to these simulations are largely informed by historical behaviour, operational understanding of specific loads, and the TBE[1] consultation process.

Power generation

Historically, NG has produced a single forecast of gas demand by the power generation sector that has performed reasonably well. However, the nature of the methodology is such that the forecast can only be relied upon if the merit order of electricity generating plant does not change significantly from one year to the next. This is because the previous year's merit order is assumed to remain largely unchanged in future years.

Industrials

The process for estimating gas demand by industrial users with direct connection to the NTS is similar to the estimation of the unrestricted demand from the power generation sector. NG calculates the expected total installed industrial capacity of this type in the forecast year as the currently installed capacity adjusted for any known additions and retirements. The forecast is based on historic patterns of consumption consistent with the expected level of installed capacity.

Exports

According to NG, forecast flow rates to and from Europe via the Interconnector are based on the assessment of relative gas prices between Europe and the UK, allowing for the seasonal variation of gas prices and resultant price differentials. Exports to Ireland are derived from a relatively simple sector-based analysis of energy markets in Northern Ireland and the Republic of Ireland, including allowances for the depletion and development of indigenous gas supplies, feedback from the TBE process, commercial sources and regulatory publications.

Forecasting performance

Table 2 reports the summary forecast performance of the NTS models over the past 12 years up to 2004/05. This illustrates that one year ahead the model has performed well on average, although in any given year the forecast ranges between +/- 2-3%. Three years ahead, the model has performed less well, with a tendency to under-estimate the actual NTS demand over the past 12 years.

1 Transporting Britain's Energy.

% Error	NTS Annual
1-year ahead absolute error	2.69%
1-year ahead error over period	-0.09%
3-year ahead absolute error	3.07%
3-year ahead error over period	-9.82%

Table 2: Summary forecast performance of the NTS model

Source: Frontier estimates based on NG data

Notes:

1) a negative number implies an under-forecast

2) estimates derived from difference between LDZ and total errors, assuming a 65:35 split between NTS and LDZ demand

It is also the case that in 2005/06 the model significantly over-estimated expected gas demand at power stations and by industrial customers. This was a consequence of the fact that the modelling methodology did not anticipate the increase in gas prices that occurred over the year, and the resulting reduction in gas demand that those prices caused. Until recently, this failure to include demand-side response to price has not had a major impact on the accuracy of the demand forecasts – largely because the price duration curve has been reasonably stable over time, so that changes in demand have been more weather-driven than price-driven. Over 2005/06 however, the price of gas has risen considerably relative to the price of other fuels, and this has led to a significant demand-side response from power generators and industrial customers. Notably, this price response has prevailed during a winter that has not been particularly severe, illustrating that prices are not driven by weather *per se*, but by the interplay of demand (that is dependent on the weather to some extent), and supply.

Main recommendations

Our discussions with NG indicate that it understands and accepts that problems can occur in demand estimation if there is a failure to take into account demand-side response to price. Therefore, for the 2006/07 WOR it intends to produce two forecasts for power generation and industrial NTS demand: a forecast of unrestricted demand using an approach which is analogous to the way in which NG has traditionally modelled gas consumption; and a forecast of restricted demand, which represents its best estimate of how much demand-side response could be expected from these sectors. However, there is no evaluation of where in this range demand would lie in the event that these customers responded rationally to higher prices at times of a tight demand-supply balance. We discuss below how an evaluation of demand responses to different price levels would be a useful addition to the forecast. This could be used to assess whether the required demand-side reductions that would be needed to achieve system balance in extreme conditions would emerge naturally as a response to higher prices or would somehow need to be compelled.

In addition, we would recommend that NG undertakes scenario analysis to improve the modelling of net export flows. This will enable a more robust assessment to be made of the extent to which the UK can realistically depend on imports when demand is high.

FORECASTS OF PEAK DEMAND AND LDCS

Having forecast the total annual gas demand, NG then profiles that demand to produce forecasts of load duration curves and peak demand under different weather conditions.

Forecasting performance

Table 3 reports the summary forecast performance of the daily modelling of LDZ and NTS models over the past 12 years up to 2004/05. On a one-year ahead basis, the models have performed well on average. The fact that the errors in peak demand are similar to the errors on an annual throughput basis suggests that the daily profiling is not noticeably adding to the errors of the forecasting process. The model is less successful, however, when forecasting on a three-year ahead basis. This is particularly the case for forecasting exports and, to a lesser extent, gas demanded by the power generation sector.

	% Error
LDZ	
1-year ahead absolute error	1.16%
1-year ahead error over period	0.33%
3-year ahead absolute error	2.41%
3-year ahead error over period	0.42%
NTS	
1-year ahead absolute error	2.11%
1-year ahead error over period	-0.35%
3-year ahead absolute error	10.71%
3-year ahead error over period	-4.93%

Table 3: Summary forecast performance of the peak demand model

Source: NG

Notes:

1) a negative number implies an under-forecast

2) estimates derived from difference between LDZ and total errors, assuming a 80:20 split between NTS and LDZ demand

For non daily metered customers and firm daily metered customers on the LDZ respectively, the daily demand forecasts continue to be accurate, reflecting the predictability of annual demand and weather-corrected load factors over time, as well as the absence of any meaningful price response amongst those customers.

However, as noted above, over the course of 2005/06 the historic one-year ahead accuracy for NTS demand has largely broken down as a consequence of increases in the price of gas leading to a demand response by large industrial customers and power generators.

Recommendations

The weather-correction and daily demand forecasting process appears to have worked satisfactorily in the past, and continues to do so for non-price sensitive customers. However, in our view, the principal cause of the recent forecast errors is that the process does not take account of a demand response by price sensitive customers to higher gas prices. Our principal recommendation, therefore, relates to augmenting the daily demand forecasts produced as part of this process, with an analysis of demand response to particular price levels. It is to this issue we now turn.

FURTHER RECOMMENDATIONS ON THE DEVELOPMENT OF THE FORECAST

As we have already indicated, NG's daily modelling does not contain a demand-side response to higher prices from price-sensitive customers. Consequently, it is difficult to assess whether the scale of demand response required to ensure demand-supply balance (as calculated by NG in Table 1 of its 2005/06 WOR) could instead be achieved as a rational demand response by customers, rather than requiring some forced curtailment of load. In principle it would seem sensible to take such a response into account when developing the 1 in 20 forecast, which is NG's planning standard.

To do this we consider how NG's approach could be augmented with an analysis of demand-side response to higher prices. This is presumed to occur amongst power station customers and industrial customers connected to both the LDZs and NTS. For the purposes of assessing the demand response, we require a profile for prices against which some response might occur, and information on the scale of the response to those prices.

Price profiles

We created two hypothetical price duration curves (PDCs). The first of these is based on actual prices observed in 2005/06. The second takes as its lower values the lower half of the 05/06 price duration curve, but the upper half is scaled up to simulate an even more extreme price response. The two hypothetical price duration curves are shown in Figure 1 for the purposes of comparison.

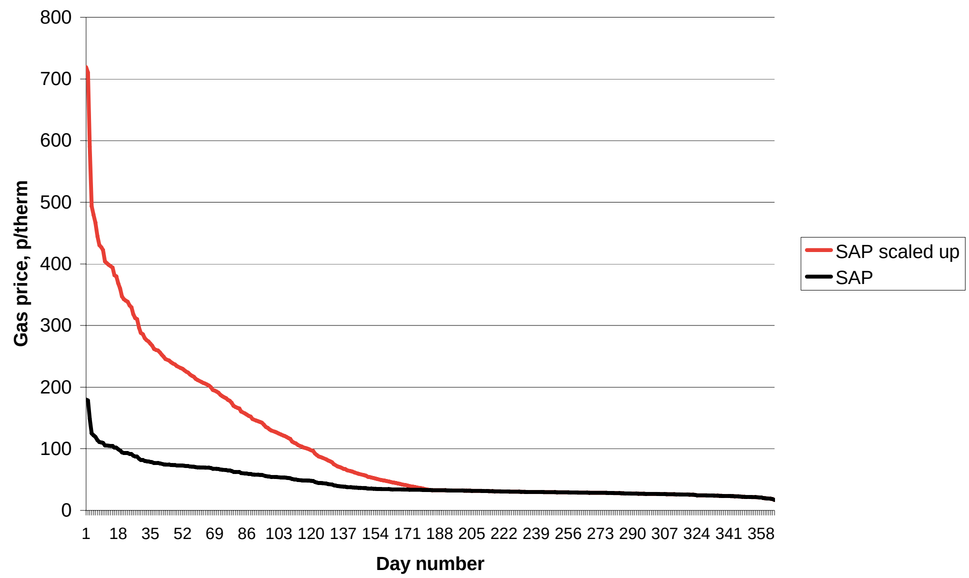

Figure 1: April 2005 – March 2006 actual and scaled up price schedules used in demand response analysis

Source: NG, Frontier calculations

The 2005/06 price schedule can be characterised as that which might occur in a normal weather year but with a supply shock, or a normal supply year in a severe winter. The scaled up price schedule could be characterised as a severe weather winter with a supply shock.

The demand responses we report here are based on the 2005/06 price schedule, whilst the results based on the scaled up price schedule is reported in Annexe 1.

Estimation of power station demand response

Our approach to estimating gas demand from the power generation sector is based on a simple, least cost marginal dispatch of available generating capacity in Great Britain. Our algorithm "stacks" power plants from cheapest to most expensive based on a range of assumed fossil fuel prices and plant efficiencies. The level of electricity demand in any given half hour can be compared to this stack in order to identify which stations are running. Given this simple dispatch pattern, we then calculate the total gas burn at different power stations. By varying the gas price we can identify gas demand for a range of possible gas prices, accounting fully for all fuel switching and running decisions.

Figure 2 below shows the potential demand response to higher gas prices from the power generation sector based on the average LDC and the 2005/06 price schedule.

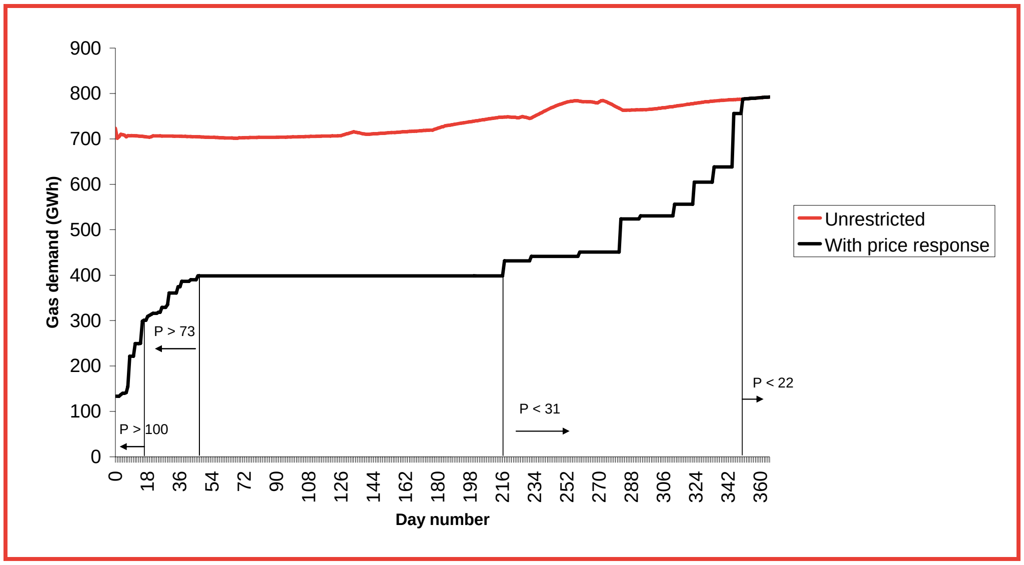

Figure 2: Demand response from power generation, average 05/06 LDC, April 2005 - March 2006 prices

Source: NG, Frontier calculations

Figure 2 shows that power generators operate in the unconstrained region (as calculated by NG) only at gas prices below around 22 pence per therm. At higher prices, a demand response can be expected as first gas becomes more expensive than coal, and then CCGTs switch to distillate if they are able to do so.

Quite clearly, the actual prices at switching occurs may not be the same as estimated here, since these will be influenced by a range of contractual, technical and planning considerations. Additionally, we know that the demand response that actually occurred in 2005/06 did not go as far as the most extreme end of the range shown in Figure 2. However, this analysis illustrates that the fundamentals of the relative prices of coal, gas and distillate could, and indeed did, provoke a significant demand-side response. In our view, this analysis of the fundamentals should form the basis for estimating the demand side response. This should then be augmented by information gathered by NG on technical and contractual factors that could limit the full extent of the potential demand side response being realised.

Industrial demand for gas

To estimate the potential price response from industrial users (connected to both the LDZ and NTS), we drew on two main sources:

- *first*, Global Insights[2] report for Ofgem and the DTI, which contained a range of estimates on the potential demand response to higher prices; and

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2 Global Insights, *Estimation of Industrial Buyers' Potential Demand Response to Short Periods of High Gas and Electricity Prices,* Report for DTI and OFGEM, May 2005.

- *second*, we conducted our own empirical analysis using a larger and more recent dataset covering the period of 1 October 2005 to 31 March 2006, where gas prices above 30 pence per therm were observed in 165 out of the 182 days.

Figure 3 below shows the price-demand relationship for the industrial sector according to three response schedules as estimated by Global Insights: theoretical, contractual and hypothetical.

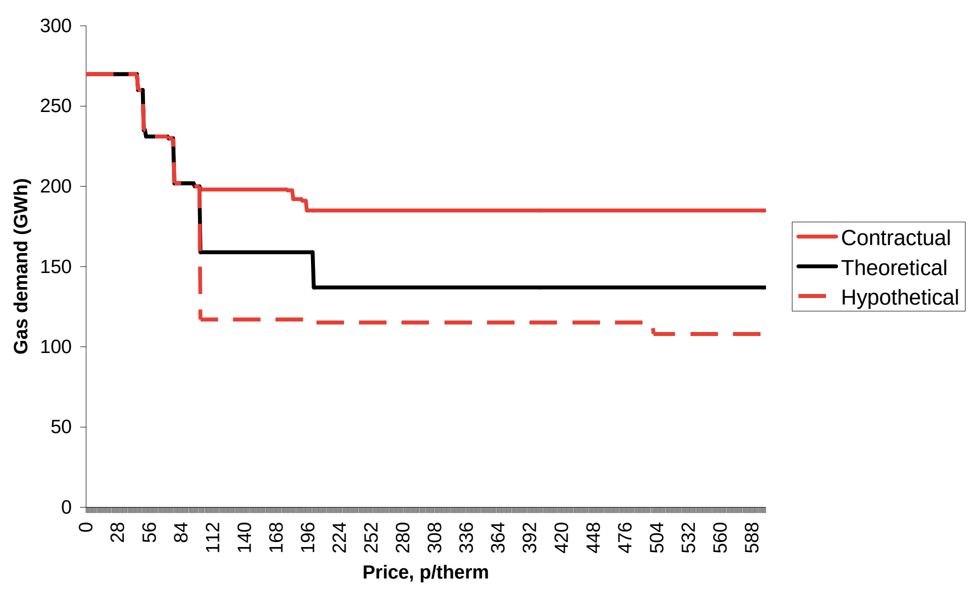

Figure 3: Gas price-demand relationship for large industrial customers according to three schedules estimated by Global Insights

Source: Global Insights Report, Figure 2-8 and Figure 2-4 in Appendix 1

Using the 2005/06 price schedule, Figure 4 below shows gas demand response by large industrial customers according to the three price-demand relationships presented in Figure 3.

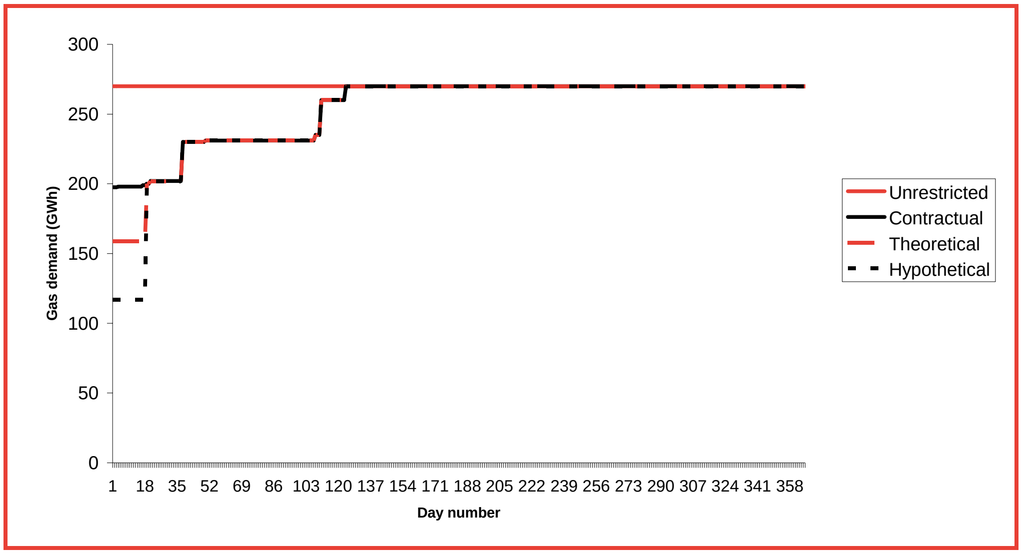

Figure 4: Demand response from the industrial sector (contractual, theoretical and hypothetical schedules), April 2005 – March 2006 prices

Source: NG, Global Insights, Frontier calculations

Impact on aggregate demand

We combine the demand response from the power generation sector and from the large industrial sector, to produce the total Load Duration Curves after the potential demand response.

Figure 5 shows the range of demand response we have estimated, encompassing NG's unrestricted forecast, our estimated response to the 2005/06 price schedule, and the estimated response to the scaled up price schedule, all for an average weather year. Figure 6 shows the range of estimated demand responses for a 1 in 50 year. Within these figures, the industrial response is modelled using the contractual schedule for the 05/06 prices, and the hypothetical schedule for the scaled up prices.

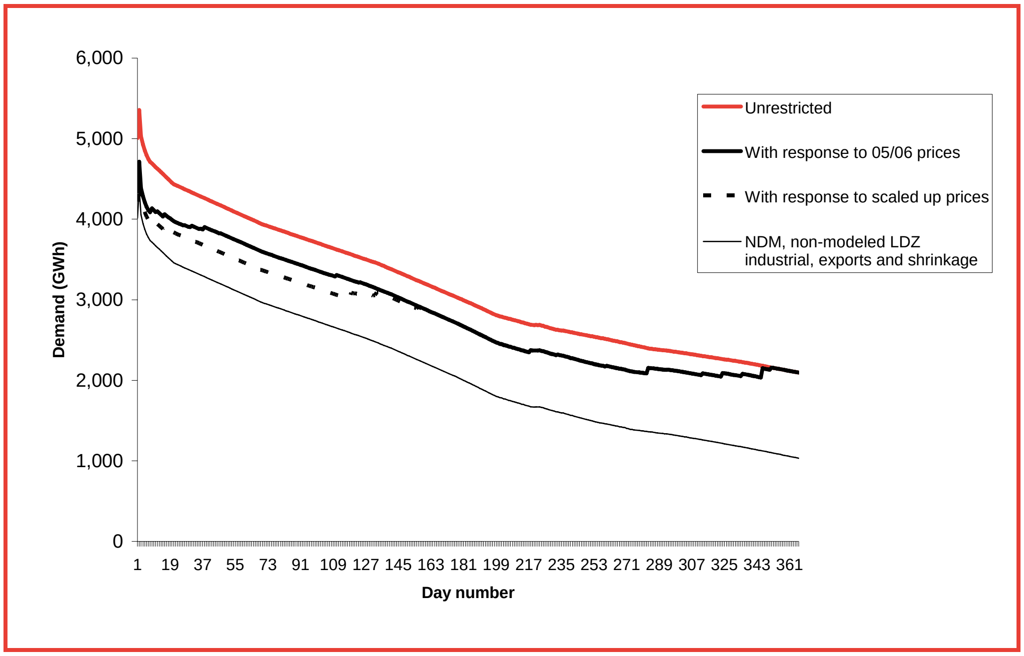

Figure 5: National average diversified LDC, unrestricted and with potential demand response

Source: NG, Frontier calculations

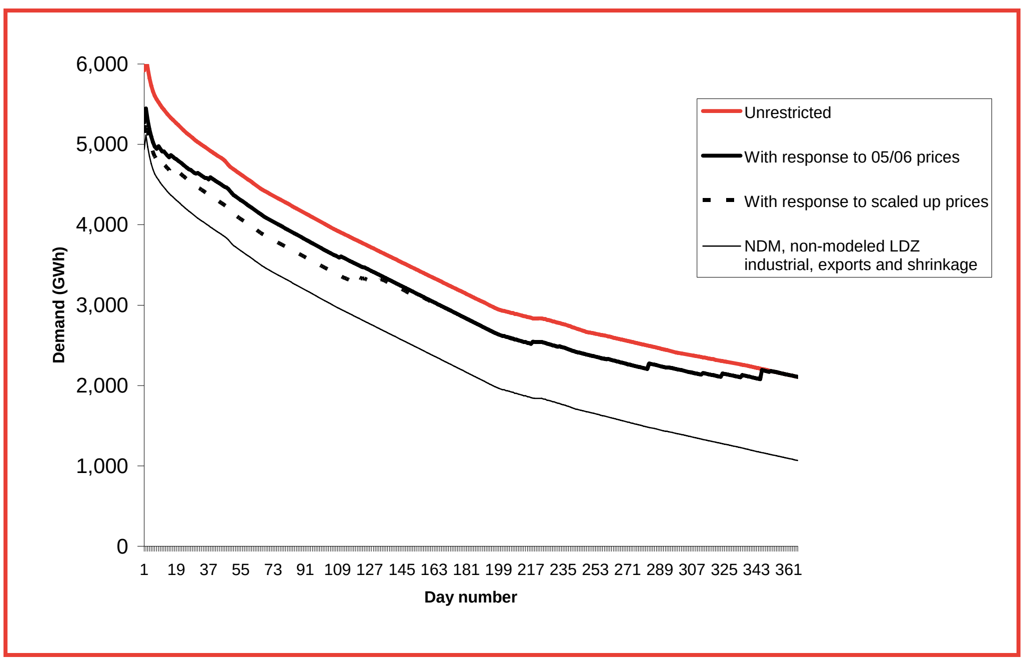

Figure 6: National 1 in 50 diversified LDC, unrestricted and with potential demand responses

Source: NG, Frontier calculations

The corresponding breakdown of demand with the response included for average and 1 in 50 winters are shown in Figure 7 and Figure 8 respectively.

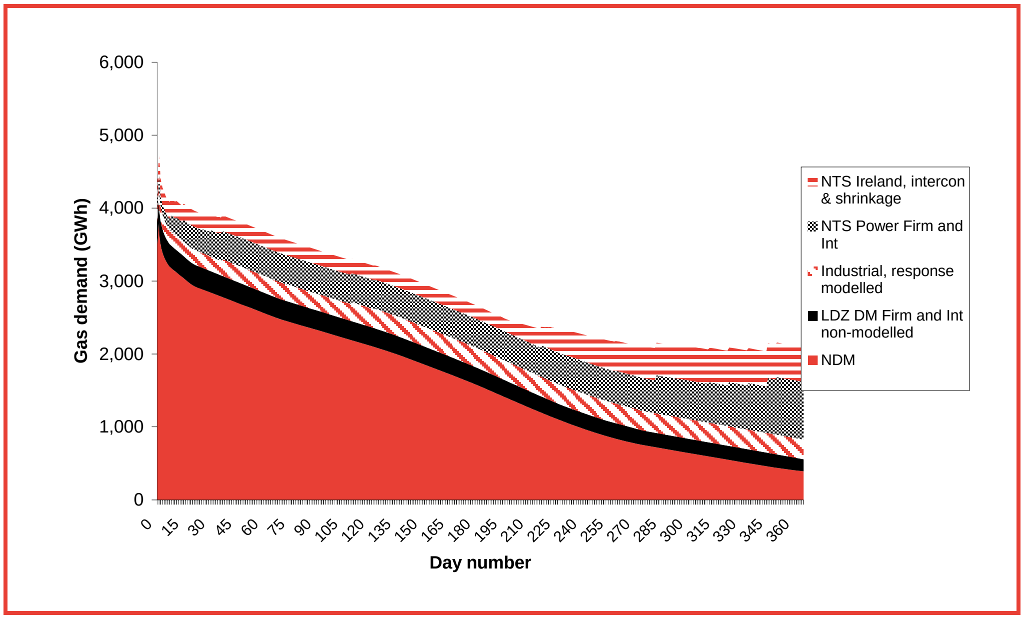

Figure 7: National average diversified LDC 2005/06, with potential demand response (April 2005-March 2006 prices, contractual response schedule for industrial customers)

Source: NG, Frontier calculations

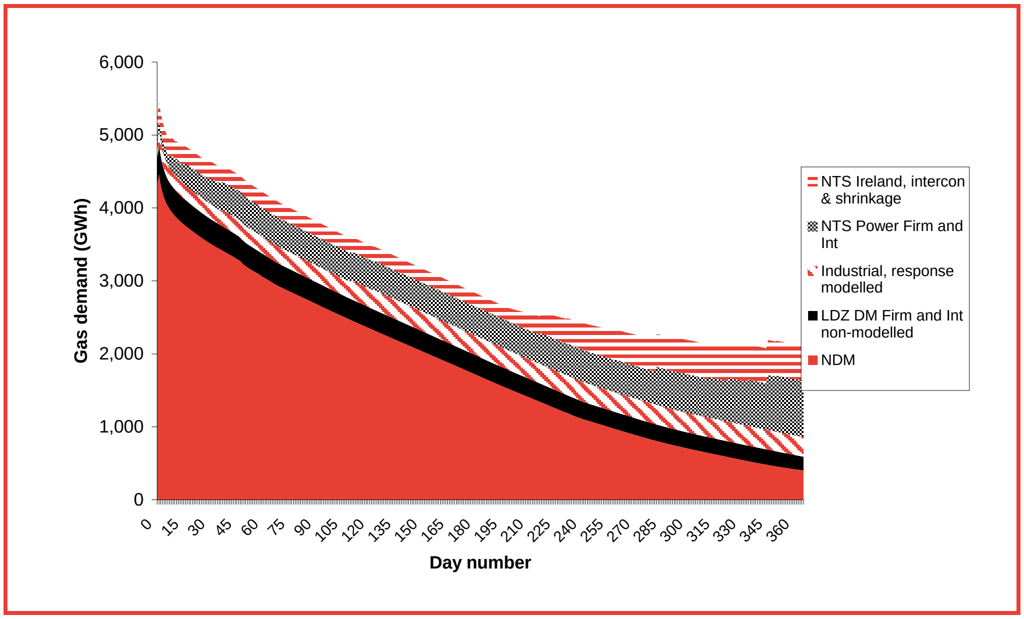

Figure 8: National 1 in 50 diversified LDC 2005/06, with potential demand response (April 2005-March 2006 prices, contractual response schedule for industrial customers)

Source: NG, Frontier calculations

Summary

The results of this exercise suggest that a significant demand response is possible under conditions of high gas prices, which could have the effect of mitigating the physical constraints that might apply in the event of supply or demand shocks. In our view it would be informative to develop this analysis further as part of the finalisation of the WOR for 2006/07.

1 Introduction

1.1 INSTRUCTIONS AND SOURCES

Ofgem has asked Frontier Economics to review the methodology underpinning the gas demand forecast employed by National Grid (NG) for the purpose of informing its Winter Outlook Report. This review is intended to:

- critique the methodological basis of the model;
- evaluate the recent forecasting performance of the model;
- undertake simulation analysis of new/alternative parameters for price elasticities;
- review the evidence-base for new/alternative parameters for price elasticities drawing on the Global Insight report for DTI and Ofgem; and
- conclude on the materiality of alternative specifications and make recommendations on further analysis that could be undertaken as part of the WOR.

The principal sources we have drawn upon are:

- *Winter Outlook Report 2005/06*, National Grid, 5 October 2005;
- *Gas demand forecasting methodology*, National Grid Transco, November 2004;
- *Demand forecasting* slidepack presented by Duncan Rimmer, NG, at Ofgem PCR workshop, 3rd February 2006;
- *Ten Year Statement*, NG, 2005;
- additional slides on demand response*, NG;*
- data for the econometric models supplied by NG;
- *Load band econometric models for 2005*, a note by NG;
- *Estimation of industrial buyers' potential demand response to short periods of high gas and electricity prices*, a report for DTI and Ofgem by Global Insight, 20th May 2005;
- daily demand and price data by load band from October 2004 to March 2006, supplied by NG; and
- Frontier Economics GB generating plant database augmented by information supplied by NG on distillate stocks held at power stations.

In addition, this report has also drawn upon information provided at two meetings between Frontier and NG staff held at NG.

This report is intended to inform the 2006/7 WOR, but a draft version of that report has not been made available to us. However, NG has made us aware of any significant methodological and presentation departures from the 2005/06 WOR that it intends for the forthcoming WOR. In principle, this report could therefore be used as a basis for a critique and review of the NG 2006/07 WOR submission, although clearly any critique of that submission would need to reflect the specific information and analysis contained therein once produced.

1.2 OVERVIEW OF THE MODELLING FRAMEWORK

NG produces two types of gas demand forecast:

- annual gas demand forecast covering a 10 year period; and
- daily/peak demand and load duration curves under different cold weather severities, which rely on the total annual forecast as one of its key inputs.

An outline structure of the modelling framework is shown in Figure 9. The forecasting process derives the peak demand forecast to inform system design issues, and the forecast load duration curves for the purpose of the Winter Outlook Report and the storage monitors.

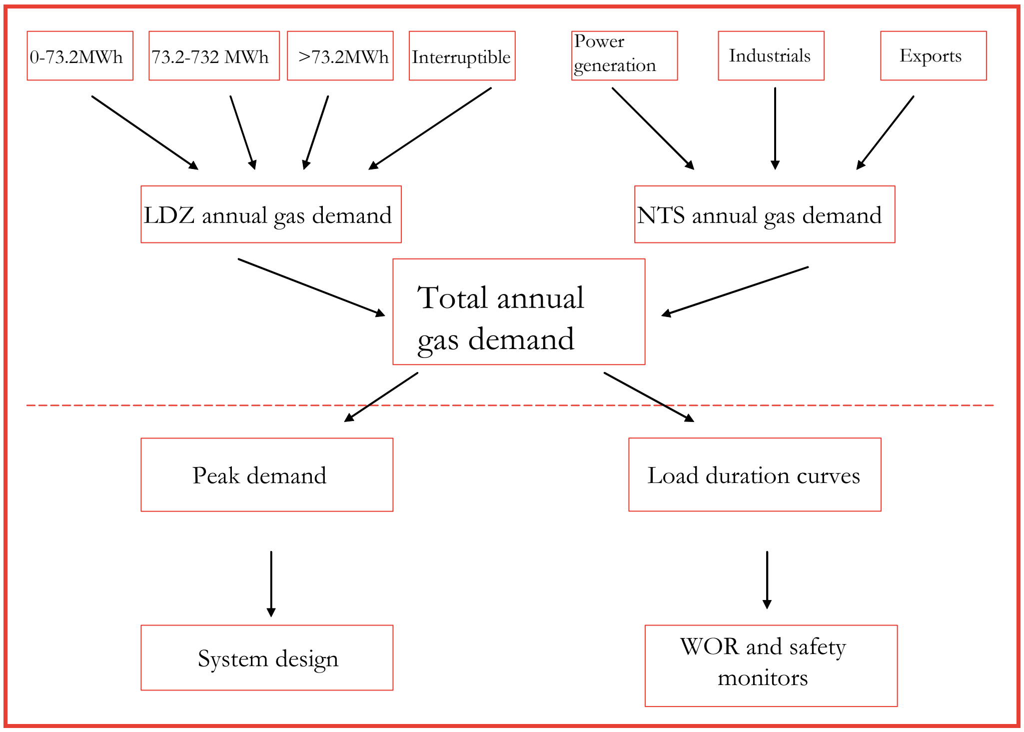

Figure 9: Model map of the NG forecasting process

Whilst the construction of both peak demand and the load duration curves for LDZs requires daily forecasts, a feature of the NG forecasting approach is that these daily forecasts derive from a forecast of annual demand for gas. This annual demand for gas is then profiled using historic daily load and weather information to provide the forecasts of peak demand and load duration curves. For NTS demand (Powergen, industrials and exports) the same process has been followed in the past, however as of the 2005/6 Winter Outlook Report, the process of estimating annual demand has also produced the high frequency data required to derive peak demand forecasts and LDCs. We note, however, that expected price levels do not play a role in this exercise. Until recently, this has not had a major impact on the accuracy of the demand forecasts – largely because the price duration curve has been reasonably stable over time, so that demand (in particular NTS demand) has been more weather-driven than price-driven. Over 2005/06 however, the price of gas has risen considerably relative to the price of other fuels, and this has led to a significant demand-side response from power generators and industrial customers. Notably, this price response has prevailed during a winter that has not been particularly severe, illustrating that prices are not driven by weather *per se*, but by the interplay of demand (that is dependent on the weather to some extent), and supply. The gas demand in each category is set out in Table 4 below.

In our view the process of deriving an annual forecast that is the profiled is reasonable for LDZ demand. However, the absence from NG's modelling of the affect of prices on Powergen and Industrial demand has been problematic.

Table 4: Annual gas demand by load category

Load band	TWh	% of total at respective pressure level	% of total throughput
0-73 MWh	425	59%	38%
73-732 MWh	64	9%	6%
> 732 MWh	114	16%	10%
Interruptible	112	16%	10%
TOTAL LDZ	**715**	**100%**	**64%**
NTS Power generation	253	63%	22%
NTS Industrials	34	9%	3%
NTS Exports	112	28%	10%
TOTAL NTS	**399**	**100%**	**35%**
Shrinkage	12		1%
TOTAL THROUGHPUT	**1126**		**100%**

Source: NG TYS, 2005

The equivalent breakdown for peak day gas demand in 2005/06 is shown in Table 5.

Load band	GWh	% of total at respective pressure level	% of total throughput
0-73 MWh	2590	66%	52%
73-732 MWh	403	10%	8%
> 732 MWh	611	16%	12%
Interruptible	319	8%	6%
TOTAL LDZ	**3,923**	100%	78%
NTS Power generation	724	71%	14%
NTS Industrials	94	9%	2%
NTS Exports	198	19%	4%
TOTAL NTS	**1,016**	100%	20%
Shrinkage	67		1%
TOTAL THROUGHPUT	**5,006**		100%

Table 5: Peak day gas demand by load category

Source: NG

Note: based on average LDC for 2005/06

1.3 STRUCTURE OF THE REPORT

The structure of the report reflects the structure of the modelling process, and the remit set out above.

In Sections 2 and 3, which relate to the annual demand forecasting on the LDZs and NTS respectively, we provide:

- a description of the methodology;
- an evaluation of the recent forecasting performance of the model; and
- recommendations on the alternative approaches that could be adopted.

In Section 4, which relates to the daily/peak and load duration curve methodology, we provide:

- a description of the methodology;
- an evaluation of the recent forecasting performance of the model; and
- recommendations on the future design of the model.

Section 5 contains Frontier's recommendations on further analysis that could be undertake, which we believe would improve the transparency and general understanding of the process. In particular, in this section we elaborate on further analysis that could be undertaken by National Grid as part of its demand forecasting process to evaluate the scope for a demand-side response from customers in the event that prices increase to reflect the greater scarcity value of gas. We undertake analysis of price responses and their implications for peak demand and load duration curves for the purposes both of illustrating the type of analysis that could usefully be undertaken in future, and to inform Ofgem in its interpretation of the information provided by NG.

Finally, in Annexe 3 we review the methodology NG uses to prepare its short term gas demand forecasts (within day, day ahead and 2-7 day). All of the work in the main report relates to the modelling required to produce peak demand and LDCs for the Winter Outlook Report. Estimation of day-ahead demand plays no role in this exercise. The generation of peak demand and LDCs forecasts and the generation of day-ahead forecasts are produced for quite separate purposes by separate teams. Nevertheless, Ofgem has requested that we also briefly consider NG's methodology for estimating day ahead demand for the purpose of establishing whether there are common strengths and weaknesses in the methodologies used for each. We undertake this task in Annexe 3.

2 LDZ annual gas demand

LDZ gas demand accounts for about 65% of total annual throughput, and is split by NG into 4 load bands for the purposes of deriving the forecast. As Table 4 above illustrates, LDZ demand is dominated by the lowest load band – the domestic sector – which accounts for around 60% of LDZ demand, with the industrial and commercial customers in the higher load bands accounting for around 40% of total LDZ throughput.

In arriving at the forecast of gas demand for LDZs, NG considers two different methodologies: the added load method and the econometric modelling method. For the domestic sector, these two alternative approaches are used to cross-check the results obtained by each individually, although NG increasingly considers econometric modelling as the primary method due to its higher reliability. For the higher load bands the two methods are used additively, as we describe later in this section.

2.1 THE ECONOMETRIC MODELLING METHOD

In the econometric modelling method, the LDZ gas demand forecast is calculated as the sum of separate forecasts for four different segments of gas consumers (by load size and supply type):

- small – annual demand between 0-73.2 MWh;
- medium – annual demand between 73.2-732 MWh;
- large – firm annual demand above 732 MWh; and
- interruptible.

The gas demand forecast in each segment is produced using a regression model chosen for that segment. All selected models are estimated using annual data over 17 years, from 1987 to 2003. In other specifications, NG also considered quarterly estimation, but encountered a problem obtaining reliable quarterly non-daily metered demand in the later years of the sample.

The dependent variable in all the models is the annual weather-corrected demand (that is, demand assuming normal weather conditions) for that segment of consumers per unit of economic activity specifically defined for the respective load band, where the economic activity indicator is different for each type of demand. For example, in the lowest load band, the dependent variable is annual weather corrected demand per household.

Weather-correction of historic annual gas demand levels is done outside the regression models as a separate modelling task. It is based on constructing a composite weather variable that relates linearly to the actual demand[3]. The outcome of the weather-correction process for each of the 17 years used in the

[3] Details of the weather-correction process are described in Section 3 of the document *Gas Demand Forecasting Methodology*, NGT, November 2004.

regressions is a demand level that would take place in that year under standard weather conditions - the seasonal normal basis for each load band is defined using 75 years of data up to 2004.

The explanatory variables in each model are limited to the gas and other relevant prices faced by customers in that load segment. Because each model is estimated for a specific load band which may include a number of different customer types, these prices are transformed from prices paid by different consumer types to prices corresponding to a given load band. This is done by weighting fuel price estimates produced by DTI for different consumer types in proportions in which those customer types are represented within a given load band. NG validates the models using a number of diagnostic tests.

- Statistical tests:
  - individual parameter significance;
  - fit of the model – measured by R-squared;
  - out-of-sample predictive power tests; and
  - model stability tests;
- Other model checks:
  - fit of equivalent DUKES model: as an independent check, it is desirable that the key drivers of the model for a load band also explain demand for a comparable DUKES sector[4]. For example, the 0-73.2 MWh pa load band is treated as 100% domestic, so if a particular set of explanatory variables provide a good model for the 0-73.2 MWh pa load band, they should also provide a good model for the DUKES domestic sector (after weather correction); and
  - economic plausibility – some models may provide a good statistical fit to the load band demand data, but may be difficult to explain in terms of the underlying economics, undermining their credibility. This is difficult to measure quantitatively, but NG ranks models in terms of their economic plausibility.

The following sections provide the exact specifications of the demand models selected by NG for each of the four demand segments.

Load size 0-73.2 MWh per annum

The 0-73.2 MWh pa load band is treated as 100% domestic. The economic activity index for the 0-73.2 MWh pa load band is an index of household numbers for Great Britain. The econometric model chosen for this load band is:

[4] Domestic, industrial and "other" sectors.

Load size 73.2-732 MWh per annum

The 73.2-732 load band is treated as 11% domestic and 89% commercial. The economic activity index for this load band is 11% of the index of household numbers plus 89% of an index of gross value added (GVA) in the commercial (non-manufacturing) sector of the economy. The econometric model chosen for this load band is:

Load size above 732 MWh per annum, firm demand

The above 732 MWh pa firm load band is treated as 48% commercial and 52% industrial. The economic activity index for this load band is 48% of the index of gross value added (GVA) in the commercial (non-manufacturing) sector of the economy plus 52% of an index of GVA in the industrial (manufacturing) sector of the economy. The econometric model chosen for this load band is:

[redacted]

Interruptible demand

The interruptible load band is treated as 100% industrial. The economic activity index for this load band is the index of gross value added in the industrial (manufacturing) sector of the economy. The econometric model chosen for this load band is:

[redacted]

Table 6 below provides a summary of the price effects in each of the four models.

Table 6: Summary of price effects in the four LDZ econometric models

Load band	If price of gas goes up by 10%, demand changes by	If price of gas and competing fuels goes up by 10%, demand changes by
0-73 MWh	[redacted]	[redacted]
73-732 MWh	[redacted]	[redacted]
>732 MWh	[redacted]	[redacted]
Interruptible	[redacted]	[redacted]

2.2 THE ADDED LOAD METHOD

2.2.1 Domestic (below 73.2MWh) load

The added load method estimates the level of domestic gas demand using a stock-and-flow approach to connections. It is built up from a number of sources:

- current number of connections;
- new connections;
- minus demolitions;

- price responses (taken from the econometric modelling for this load band);
- efficiency improvements (taken from buildings research); and
- a comfort factor, reflecting changing use of gas for heating.

NG increasingly uses the added load method only as a supplementary cross-check for the main econometric modelling method, because the information on some of these factors is getting less reliable.

2.2.2 I&C (above 73.2MWh and interruptibles) load

The added load method estimates the maximum potential gas demand by LDZs during the forecast year using the following components:

- added new loads (using the number of new connections);
- minus decommissioned loads;
- the resulting total installed loads adjusted by an estimated efficiency improvement factor; and
- the resulting maximum potential demand adjusted for an expected gas price change (using not an explicit price elasticity, but rather a simple "manual" adjustment to the total expected demand based on NG expert view of how gas price interacts with demand).

The resulting added load forecast is then added to the econometric forecast (which forecasts demand from existing loads) to produce a total gas demand forecast from the I&C sector[5].

2.3 FORECASTING PERFORMANCE

In this section we review the forecasting performance of the annual model. Table 7 reports the summary forecast performance of the LDZ model over the past 12 years, which illustrates that 1-3 years ahead, the model performs well on average, although the average absolute size of the forecasting error in any given year ranges from +/-1.2% one year-ahead, increasing to +/- 4% three years ahead.

5 NG has indicated to us that it is aware of a potential double-counting problem in that the econometric analysis will already capture new loads coming and old loads disappearing over the regression sample. We understand that NG attempts to deal with this by restricting the regression sample.

% Error	LDZ Annual
1-year ahead absolute error	1.18%
1-year ahead error over period	-0.06%
3-year ahead absolute error	4.41%
3-year ahead error over period	0.81%

Table 7: Summary forecast performance of the LDZ model

Source: NG

Note: A negative number implies an under-forecast

Table 8 shows forecast performance by load band between 2000 and 2004 in more detail. Forecasting performance in 2005/6 is considered in section 4 on daily demand forecasting performance.

The table illustrates that over the 5 years, the model had a slight tendency to over-forecast total LDZ demand, and that this appears to have been driven by over-forecasting the larger firm and interruptible loads.

In summary, it appears that the LDZ regressions perform reasonably well, largely because of the stability of the domestic load.

	2000				2001				2002				2003				2004			
TWh	Actual Demand	Weather Corrected Demand	Reconciliation Corrected Forecast	% difference	Actual Demand	Weather Corrected Demand	2001 10 YS Forecast Demand	% difference	Actual Demand	Weather Corrected Demand	2002 10 YS Forecast Demand	% difference	Actual Demand	Weather Corrected Demand	2003 TYS Forecast Demand	% difference	Actual Demand	Weather Corrected Demand	2004 TYS Forecast Demand	% difference
0-73 MWh	382	393	392	-0.3	407	405	404	-0.2	381	411	409	-0.5	394	416	415	-0.2	405	421	418	-0.7
73-732 MWh	59	62	60	-3.2	61	61	63	3.3	58	63	61	-3.2	61	64	63	-1.6	61	64	65	1.6
>732 MWh Firm	142	144	151	4.9	141	141	141	0.0	138	142	144	1.4	135	138	143	3.6	131	134	136	1.5
Interruptible	123	125	133	6.4	108	110	120	9.1	110	111	111	0.0	104	105	112	6.7	102	102	103	1.0
LDZ Total	**706**	**724**	**736**	**1.7**	**717**	**717**	**728**	**1.5**	**687**	**727**	**725**	**-0.3**	**695**	**724**	**733**	**1.2**	**700**	**721**	**722**	**0.1**

Table 8: Annual LDZ demand forecasting performance (1 year ahead), 2000-2004

Source: NG

LDZ annual gas demand

2.4 RECOMMENDATIONS

2.4.1 Recommendations for this WOR

As far as the LDZ annual forecasts are concerned, there is, as we discuss below, strong arguments in favour of moving to quarterly modelling to improve the robustness of the analysis and the forecasts. However, for the 2006/07 WOR, the scope to perform sensitivity analysis that would be sensible in a probabilistic sense is more limited. As we discuss in section 5, there is a range of sensitivities that should be undertaken for the daily demand modelling of power generation and industrial demand (including LDZ industrial demand) for the forthcoming WOR and in our view that should take priority, since that area of the forecast is also the one where the largest forecasting errors have been observed.

2.4.2 Medium term recommendations

Consider using quarterly data in regressions

There are significant benefits to be obtained by moving from annual to quarterly data in the regression analysis. There are three main benefits of using quarterly data in regression analysis.

- **Improved robustness of the estimates**

A formal statistical measure of the range of uncertainty around a given estimate is called the standard error of that estimate. Under standard regression assumptions, the size of the standard error is inversely related to the square root of the number of observations used in the estimation minus the number of explanatory variables included in the model. For example, if the number of observations increases by 4 times then - other things being equal and the number of explanatory variables being small - the range of uncertainty around the estimate decreases by approximately 2 times.

This becomes crucially important in a situation with a low number of observations, because the starting range of uncertainty in that case is relatively large. This is one of the key arguments in favour of trying to increase the number of observations in the demand forecast regressions by 4 times by moving from annual to quarterly data.

- **Possibility to conduct model testing more reliably**

One concern with the low number of observations is that the standard statistical tests based on historical data would show a very good fit, but the model might not be as useful for predicting demand in the future. An example of this is the set of price responses shown in Table 6. In one load band an increase in all fuel prices increases gas demand significantly whilst in another it reduces it significantly. There does not seem to be a compelling economic case for such a very different set of prices responses, which could be investigated in greater depth on higher frequency data.

Increasing the number of observations by moving from annual to quarterly data could greatly reduce this concern, by lowering the probability of a spurious/chance fit.

- **Possibility to include more variables**

Each explanatory variable added to the right-hand side of a regression model reduces the precision of estimates obtained from such model, and this effect is similar to reducing the number of observations by 1. Correspondingly, in a situation when the number of observations is low, the scope for including a larger number of potential explanatory variables may be limited, as that could make regression estimates very imprecise.

Increasing the number of observations from 17 to 68 by moving from annual to quarterly data would enable NG to test a larger number of alternative model specifications, including those with larger sets of explanatory variables if necessary. The value of moving from annual to quarterly data, given that the relationships in question appear relatively stable, is that if there are sharp and persistent price shocks, it is more likely that the forecast based on quarterly data will predict the impact of that price increase on demand, compared to the current annual approach, where the impact of prices is less well determined.

3 NTS annual gas demand

NTS demand includes forecast gas demand from loads with their own connection to the NTS. NG groups these loads into three types:

- power generation;
- industrials; and
- exports (net flow to and from Northern Ireland, the Republic of Ireland and the European Interconnector).

As the table below illustrates, NTS demand accounts for around 35% of total throughput, and by far the largest source of gas demand on the NTS is from power stations.

Load band	TWh	% of total at respective pressure level	% of total throughput
TOTAL LDZ	**715**	**100%**	**64%**
NTS Power generation	253	63%	22%
NTS Industrials	34	9%	3%
NTS Exports	112	28%	10%
TOTAL NTS	**399**	**100%**	**35%**
Shrinkage	12		1%
TOTAL THROUGHPUT	**1126**		**100%**

Table 9: Gas demand by load category

Source: NG TYS, 2005

Unlike the LDZ demand modelling, NTS demand is not modelled using regression analysis but is instead modelled through simulations of expected future demand where the inputs to those simulations are largely informed by historical behaviour, operational understanding of specific loads, and the TBE[6] consultation process. The approaches used in estimating NTS demand in each of the three categories are described in the following sections.

6 Transporting Britain's Energy

3.1 MODELLING APPROACH

3.1.1 Power generation

Historically, NG has produced a single forecast of gas demand by the power generation sector that has performed reasonably well. However, the nature of the methodology is such that the forecast can only be relied upon if the merit order of electricity generating plant does not change significantly from one year to the next. This is because, as discussed below, the previous year's merit order is the basis for future forecasts and is assumed to remain largely unchanged in future years. In 2005/06 the merit order did change quite considerably, with coal displacing gas, which led to much reduced gas demand relative to forecast.

Our discussions with NG indicate that it understands and accepts this point, and for the forthcoming WOR it intends to produce two forecasts, the basis for which we describe in more detail below: a forecast of unrestricted demand using an approach which is analogous to the way in which NG has traditionally modelled gas consumption at generating stations; and a forecast of restricted demand, which represents its best estimate of how much gas-fired generation could be turned down.

As we discuss in section 5, in our view it would also be helpful to evaluate *whether* gas demand could be expected to reduce as a consequence of increases in the relative price of gas due to a tightening demand-supply balance, and the price(s) at which these effects would occur.

The unrestricted demand forecast

The *unrestricted* demand determined by installed capacity, consists of two steps:

- *first*, the total generation capacity that would be available over the forecast year across all fuel types is estimated; and
- *second*, the total annual demand for gas by the power generation sector is estimated by looking how frequently, and when, the gas-fired capacity would be used.

- Estimating total generation capacity

NGT estimates the total generation capacity that would be available over the forecast year as the opening capacity stock, plus expected new installed capacity, minus expected decommissioned capacity.

Data to inform this calculation comes from a variety of sources, including:

- connections requests and load enquiries;
- feedback gathered in the TBE consultation process; and
- a range of commercial sources.

NGT also considers the influence of new entrant viability, commercial arrangements, government policies and legislation when forecasting which power stations will be built or closed.

- Estimating gas demand from the generation sector

NGT then estimates which of the total installed generation capacity will be actually used over the forecast period, and how frequently. The gas-fired component of this actually employed generation capacity provides the estimate of the annual gas demand from the sector.

The estimation is based on the information about the generation mix and availability factors over a recent historic period. This period is often the most recent for which data are available (i.e., just the last year); however, if NG feel that the last year's data was not representative for some reason (say, because a large power plant was closed in that year, and that effected the ranking order of all plants and hence the fuel types), then NG uses data for a longer historic period (up to three years).

Generation mix and availability proportions obtained from the historical data are then applied straightforwardly to the total installed capacity in the forecast year, to obtain the estimated gas demand from the generation sector. The starting point for this process is that the historically observed merit order does not change, but adjustments are made to this if there is good reason to suppose that the merit order will change in future. However, NG has acknowledged that the changes it has typically made are not significant (and certainly were not made on the scale that actually did reflect the changes in the merit order in the current year), and it is this that has led NG to produce its restricted demand forecast.

The restricted demand forecast

In the current year (2005/06) the actual gas demand by the power generation sector turned out significantly smaller than the maximum potential demand as estimated by NG. This difference was due to demand-side responses from the sector to dramatically increased gas prices, in the form of voluntary reductions in the use of gas.

Recognising this difference, NG has started producing an additional measure of the forecast gas demand in the power generation sector, the *restricted* demand. The methodology used by NG for estimating the minimum potential gas demand from power generation is organised around different types of operational information available for each individual power station, rather than just fuel prices. NG assesses the maximum potential for shutdowns/interruptions/fuel switching there is operationally in the power generation market. NG has told us that it takes into account:

- whether a given power plant operates under a long-term gas supply contract with the price of gas fixed – in which case NG would normally assume that this power plant is not exposed to the high spot price of gas, and so would not reduce its gas consumption (however, the assumption may be different if it is known that a specific power plant with a long-term supply contract would nevertheless change its gas consumption in response to the current spot prices);
- whether the gas supply contract for a given power plant is interruptible or not, and if so, what is the maximum scope for interruption;

- whether a given gas-powered plant is part of a portfolio of generation capacities owned by the same owner, and so could possibly be switched off while power is supplied by those plants in the portfolio that use a different fuel;
- whether, in addition to technological feasibility, the geographical location of a given power plant would allow it to substitute gas with another type of fuel; and
- any information obtained through the TBE consultation process with the industry. For example, if it becomes known that for some reason a given power plant would operate as a base or a peak load over a specified period of time, that information would be explicitly reflected in the final estimate of the power generation dispatch across the industry.

The resulting estimate of the restricted gas demand serves as the lower boundary for the range where the actual gas demand from the power generation sector may turn out to be. The actual gas demand would be higher than the minimum potential demand if not all possible gas supply interruption/voluntary demand reduction options considered by NG would actually be used by the industry. Equally, however, it is possible that gas demand could be lower than estimated, if NG's assumptions turn out to be falsified.

3.1.2 Industrials

The process for estimating gas demand by industrial users with direct connection to the NTS is similar to the estimation of the maximum potential demand from the power generation sector. NG calculates the expected total installed industrial capacity of this type in the forecast year as the currently installed capacity adjusted for any known additions and retirements. The forecast is based on historic patterns of consumption consistent with the expected level of installed capacity. As with the power generation forecast, this estimate could in principle be modified to reflect the expected relative fuel price conditions over the forecast period, although in practice we understand that these modifications have been minor.

The sources of information for this exercise are broadly similar to those used in the power generation gas demand forecast, and additionally takes account of the feedback received as part of NG's consultation process.

The restricted potential demand forecast was not calculated for the 2005/6 WOR but NG has indicated to us that it intends to produce this forecast for the 2006/07 WOR. As with the power generation model, in section 5 we discuss the prospects for evaluating whether industrial gas demand (from the NTS as well as the LDZs) would be reduced as a consequence of increases in the relative price of gas due to a tightening demand-supply balance.

3.1.3 Exports

According to NG[7], forecast flow rates to and from Europe via the Interconnector are based on the assessment of relative gas prices between Europe and the UK, allowing for the seasonal variation of gas prices and resultant price differentials. Exports to Ireland are derived from a relatively simple sector-based analysis of energy markets in Northern Ireland and the Republic of Ireland, including allowances for the depletion and development of indigenous gas supplies, feedback from the TBE process, commercial sources and regulatory publications.

Modelling of export flows between regions is complex. Given perfect information and no transaction costs, gas will flow from cheaper regions to more expensive regions until either the price difference is eliminated, or the interconnector is full. It therefore follows that model of export flows must have at its core an assessment of price spreads. However, in practice, there is a range of factors that might lead to outcomes (i.e. physical flows and prices) that depart from this optimal efficient outcome. Possible explanations include the existence of contracts (either in GB or elsewhere) that reduce physical flexibility in the short term, thereby making some market participants unable to respond fully to short term price differences. Similarly, the operation of gas storage in other regions might limit the extent of any physical response in the short term. Rigidities of this kind can also create transaction costs that make responding to short term price differentials unprofitable. In addition, it is possible that lower than anticipated physical flows might arise due to the exercise of market power by large producers. Modelling all of these factors would require a substantial effort and would require access to a wide range of potentially commercially confidential information.

NG acknowledges that the gas demand forecast for the import/export segment is the least formalised compared to all segments discussed earlier, and is based largely on qualitative views taken by NG about the relationship between, for example, alternative relative price scenarios and realised import/export gas flows. We concur with NG's assessment and present some options for further refinement below.

3.2 FORECASTING PERFORMANCE

In this section we review the forecasting performance of the annual model. Table 7 reports the summary forecast performance of the NTS models over the past 12 years, which illustrates that 1 year ahead the model has performed well on average although in any given year the forecast ranges between +/- 2-3%. Three years ahead, the model has performed less well, with a tendency to under-estimate the actual NTS demand over the past 12 years.

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7 *Gas Demand Forecasting Methodology*, National Grid Transco, November 2004.

% Error	NTS Annual
1-year ahead absolute error	2.69%
1-year ahead error over period	-0.09%
3-year ahead absolute error	3.07%
3-year ahead error over period	-9.82%

Table 10: Summary forecast performance of the NTS model

Source: Frontier estimates based on NG data

Notes:

1) a negative number implies an under-forecast

2) estimates derived from difference between LDZ and total errors, assuming a 65:35 split between NTS and LDZ demand

However, as Table 11 shows, between 2000 and 2004 the model had a greater tendency to over-estimate NTS demand, and this was driven almost exclusively by over-estimating exports. Forecasting performance in 2005/6 is considered in section 4 on daily demand forecasting performance.

	2000				2001				2002				2003				2004			
TWh	Actual Demand	Weather Corrected Demand	Reconciliation Corrected Forecast	% difference	Actual Demand	Weather Corrected Demand	2001 10 YS Forecast Demand	% difference	Actual Demand	Weather Corrected Demand	2002 10 YS Forecast Demand	% difference	Actual Demand	Weather Corrected Demand	2003 TYS Forecast Demand	% difference	Actual Demand	Weather Corrected Demand	2004 TYS Forecast Demand	% difference
Industrial	31	31	32	3.2	32	32	35	9.4	33	33	31	-6.1	36	36	36	0.0	35	35	36	2.9
Power Generation	195	196	194	-1.0	210	212	216	1.9	228	229	219	-4.4	224	225	226	0.4	244	245	240	-2.0
Exports	154	154	150	-2.6	145	146	158	8.2	158	158	169	7.0	183	183	192	4.9	119	119	137	15.1
NTS Loads	**380**	**381**	**376**	**-1.3**	**387**	**390**	**409**	**4.9**	**419**	**420**	**418**	**-0.5**	**442**	**443**	**454**	**2.5**	**398**	**399**	**413**	**3.5**

Table 11: Annual NTS demand forecasting performance (1 year ahead), 2000-2004

Source: NG

NTS annual gas demand

3.3 RECOMMENDATIONS

3.3.1 Recommendations for this WOR

As discussed above, the approach which NG plan to adopt for the WOR (2006/07) is to estimate an unconstrained and a constrained case which provide a range around which demand for gas from power stations and industrial customers could lie. However, there is no evaluation of where in this range demand would lie in the event that these customers responded rationally to higher prices at times of a tight demand-supply balance. As we discuss in section 5, an evaluation of demand responses to different price levels would be a useful addition to the forecast to assess whether the required demand-side reductions necessary to achieve system balance in extreme conditions would emerge naturally as a response to higher prices or would need to be compelled in some form.

3.3.2 Medium term recommendations

Power generation

The medium term recommendations focus on the extent to which it is appropriate to base a forecast of the future gas peak demand by power generators on a backward-looking model. For power generation, it is possible to undertake simulations of expected electricity production through traditional dispatch models that provide outputs on a half-hourly basis. Consequently, NG may want to consider modelling daily demand explicitly.

A forecast of the actual gas demand in the power generation sector would involve undertaking a formal forward-looking dispatch analysis for a sufficient number of representative days over the year. This type of analysis produces a least-cost merit order of plant that is required to run to meet particular levels of electricity demand. This approach does require a reasonably detailed set of information, but this should be available at NG or from other sources.

This analysis would ideally comprise a number of scenarios:

- A base case, which reflects the best estimates of the prices of fuel that is used to generate electricity.
- A number of price scenarios to evaluate the impact on gas demand at power stations:
  - low gas price (relative to other fuels), which would imply a forecast close to that which NG has described as its unconstrained case; and
  - progressively higher gas prices (relative to other fuels) to inform the extent to which CCGTs switch away from gas to distillate or ramp down completely.

These analyses, appropriately augmented, would then feed directly into the daily demand forecasts, construction of load duration curves and peak demand. This could be then used in one of two ways. Either it could be formally tied into the forecasting process so that the determination of the demand-supply balance is internally consistent with the demand response expected from power generators and industrials given the fuel price assumptions used; or this analysis could be de-coupled from the main process and instead used to evaluate the reasonableness of rational demand responses leading to an alleviation of a tight demand-supply position, if the unrestricted analysis indicates that such a position may indeed prevail. We provide an illustration of such an approach in section 5.

Industrials

The current approach could be extended to more formally consider the extent to which switching to other fuels or shutting down of production could occur if the relative price of gas rose significantly. In section 5 we illustrate how price responses of non-power station daily metered demand (NTS and LDZ combined) could feed into the presentation of the demand forecasting.

Exports

As NG has acknowledged, the export forecasting process is the least formalised element of the demand forecast. However, for estimating 1 in 20 demand, this effect may not matter too much since exports to continental Europe may not materialise in such conditions, i.e. there will almost certainly be no exports when UK gas supply is heavily constrained. The key issue, therefore, is likely to be the extent to which the UK can depend on imports in such circumstances. In order to understand potential imports better, there is a range of approaches that NG could adopt that vary in their sophistication and resource requirements. The most sophisticated approach would be to construct a model of the European gas market, that would take account of conditions on both sides of the relevant interconnectors in order to estimate likely gas flows more robustly. An approach of this kind is likely to be resource intensive and complex to implement. An alternative approach would be to undertake some more limited scenario analysis of the potential for import flows and how those flows vary with certain key variables.

At this stage, our recommendation is that NG undertakes scenario analysis to improve their modelling of net export flows.

4 Forecasts of peak demand and LDCs

Having forecast the total annual gas demand, NG then profiles that demand to produce forecasts of load duration curves and peak demand. For the WOR up to but not including the 2005/06 Report, the methodological basis for undertaking this exercise was reported in NGT's *Gas demand forecasting methodology*, of November 2004.

As the table below illustrates, the basis for the profiling is in some cases the simulation described in this section, and in other cases the profile is determined by residual.

	Firm	Interruptible	Total
LDZ	Simulate	Residual: Total - firm	Simulate
NTS	Residual: GB total-shrinkage-LDZ	Residual: Total - firm	Residual: GB total-shrinkage-LDZ
Shrinkage	Assumption	Residual: Total - firm	Assumption
GB Total	Simulate	Residual: Total - firm	Simulate

Table 12: Matrix of diversified peak and load duration curves

Source: NG, Gas demand forecasting methodology, November 2004, Appendix 3

Clearly, if the historical profiles for LDZ demand and total GB demand are relatively stable, then the historical profile for NTS demand has also been relatively stable, and the approach of treating NTS demand as a residual would not create significant forecasting errors. However, if there is instability in daily demand in the forecast period, compared to the past, then this cannot be picked up by the model.

For the 2005/06 WOR, NG has told us that it models daily demand for gas at power stations directly - rather than by residual - using the methodology set out in the annual demand modelling described in section 3. Increasingly also, exports and industrials are modelled (or assumptions made) off-model to derive a profile for that demand that can be added to LDZ demand and power station demand – which is more formally modelled. NG intends to continue with this approach for the forthcoming WOR. As a consequence, NG's approach can now be more accurately characterised by Table 13.

	Firm	Interruptible	Total
LDZ	Simulate	Residual: Total - firm	Simulate
NTS (power stations)	Estimated directly as a product of the annual demand modelling	Residual: Total - firm	Estimated directly as a product of the annual demand modelling
NTS (exports and industrials)	Assumption/ analysis	Residual: Total - firm	Assumption/ analysis
Shrinkage	Assumption	Residual: Total - firm	Assumption
GB Total	SUM OF THE ABOVE	Residual: Total - firm	SUM OF THE ABOVE
GB Total – cross check	Simulate	Residual: Total - firm	Simulate

Table 13: Matrix of diversified peak and load duration curves

Source: NG, Gas demand forecasting methodology, November 2004, Appendix 3

NG's *Gas demand forecasting methodology*, describes the this approach in detail, but fundamentally the methodology for estimating the load duration curves for LDZ demand follows a number of key steps.

- **Production of forward-looking daily demand**
  - the annual demand forecast is, by definition, based on normal seasonal conditions (i.e. it is an annual measure of seasonal normal demand);
  - the annual demand forecast is shaped using a daily seasonal normal demand (SND) profile;
  - the SND profile is derived from a regression of daily demand on a composite weather variable (CVW); and
  - the CWV is comprised of several characteristics that are transformed in order to produce a linear relationship with LDZ demand – the components of the CWV include:
    - effective temperature (0.5 * today's temperature + 0.5 * yesterday's effective);
    - seasonal normal effective temperature;
    - wind chill;
    - cold weather upturn; and
    - summer cut-off.

- **Simulation of demands under alternative weather conditions:**
  - the daily demands under seasonal normal conditions are updated to reflect what demand would be if historical weather in a particular gas year was to be repeated in the same order as it originally occurred; and
  - this exercise is repeated for each of the 75 gas years in the weather history, then with the weather pattern lagged and led 3 days in each year to ensure that extreme weather occurs on every day of the week; and finally under two alternative random processes, to yield 28 simulations for each weather year.
- **Calculation of the 1 in 20 peak day:**
  - for each of the 28 simulations over the 75 gas years there is a single simulated maximum demand; and
  - a distribution is fitted to these values, and all estimates in the 95% value from this distribution are averaged to give the 1 in 20 peak day estimate.
- **Calculation of the 1 in 50 load duration curves**
  - A load duration curve shows an estimate of the total demand in a gas year above any specific demand threshold (see Figure 1 for a stylised chart of a load duration curve). The 1 in 50 Load Duration Curve is a load duration curve in which each demand threshold is exceeded, statistically, with the probability of 2% (i.e., in 1 in 50 years). These probabilities are derived similarly to the calculation of the 1 in 20 peak day, but undertaken across the entire demand in a year.

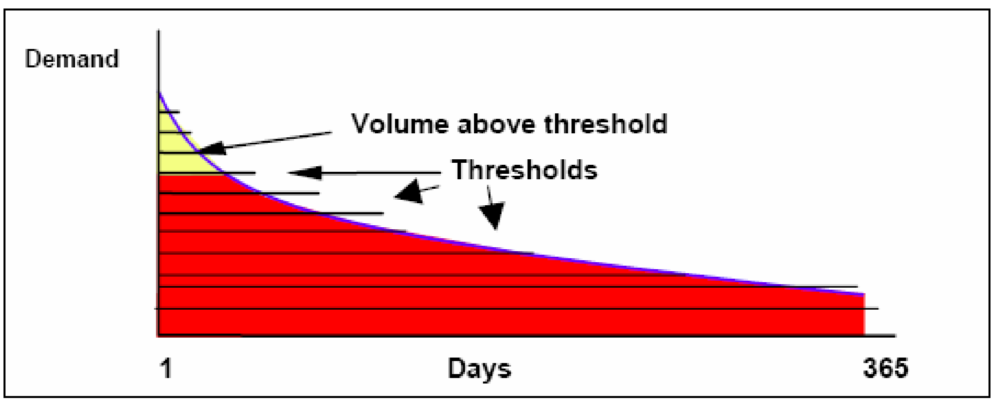

Figure 10: Example of a load duration curve

4.1 FORECASTING PERFORMANCE

Table 14 reports the summary forecast performance of the daily modelling of LDZ and NTS models over the past 12 years. On a 1-year ahead basis, the models have performed well on average, and the fact that the errors in peak demand are similar to the errors on an annual throughput basis suggests that the daily profiling is not noticeably adding to the errors of the forecasting process.

Where the model is less successful is on a 3-year ahead basis, especially in the power generation sector.

	% Error
LDZ	
1-year ahead absolute error	1.16%
1-year ahead error over period	0.33%
3-year ahead absolute error	2.41%
3-year ahead error over period	0.42%
NTS	
1-year ahead absolute error	2.11%
1-year ahead error over period	-0.35%
3-year ahead absolute error	10.71%
3-year ahead error over period	-4.93%

Table 14: Summary forecast performance of the peak demand model

Source: NG

Notes:

1) a negative number implies an under-forecast

2) estimates derived from difference between LDZ and total errors, assuming a 80:20 split between NTS and LDZ demand

Over the course of 2005/06, the historic 1-year ahead accuracy has largely broken down as a consequence of a tightening of the demand-supply balance causing an increase in the price of gas, leading to a demand response by large industrial customers and power generators.

Figure 11 and Figure 12 illustrates that for non daily metered customers and firm daily metered customers on the LDZ respectively, the daily demand forecasts continue to be accurate, reflecting the predictability of annual demand and weather-corrected load factors over time, as well as the absence of any meaningful price response amongst those customers.

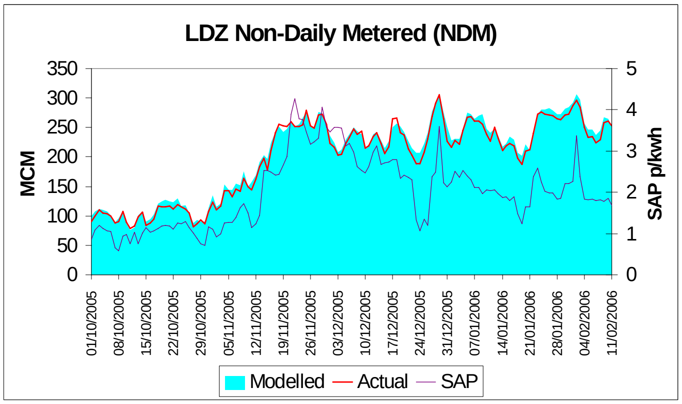

Figure 11: LDZ NDM (firm) - comparison of actual and forecast values

Source: NG, Demand response slide pack sent to Frontier

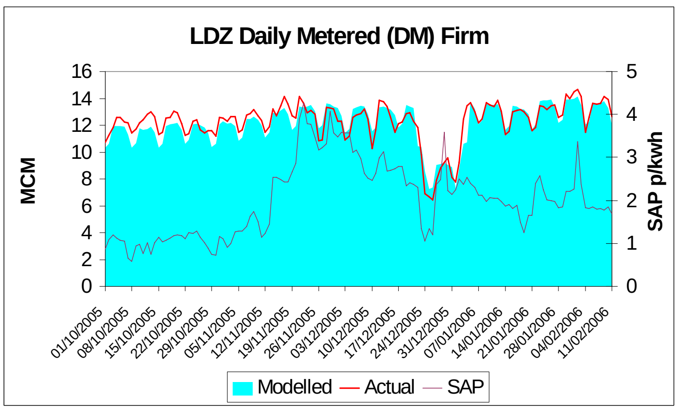

Figure 12: LDZ DM (firm) - comparison of actual and forecast values

Source: NG, Demand response slide pack sent to Frontier

In contrast, Figure 13 shows that for LDZ daily metered interruptible customers, a significant demand response to higher gas prices was observed from November 2005[8].

8 We understand from NG that a similar effect occurred for industrial customers on the NTS, but the data presenting this information has not yet been made available to us.

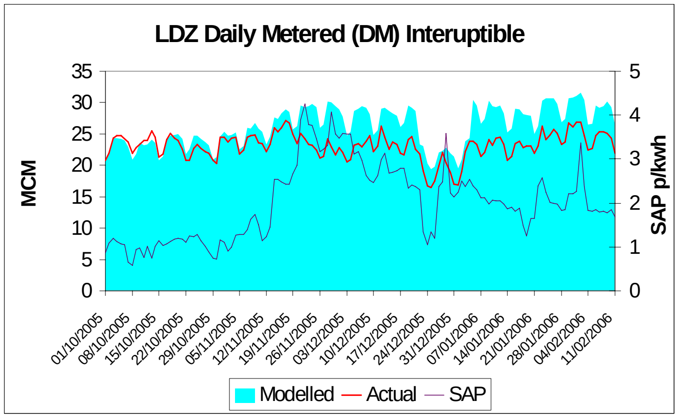

Figure 13: LDZ DM (interruptible) - comparison of actual and forecast values

Source: NG, Demand response slide pack sent to Frontier

Gas demand at power stations illustrates an even more marked response, as Figure 14 shows. NG has presented information to us, reproduced in Figure 15 that illustrates its view that this demand response (which did not arise in previous years) was due to gas price levels that had not prevailed in the recent past.

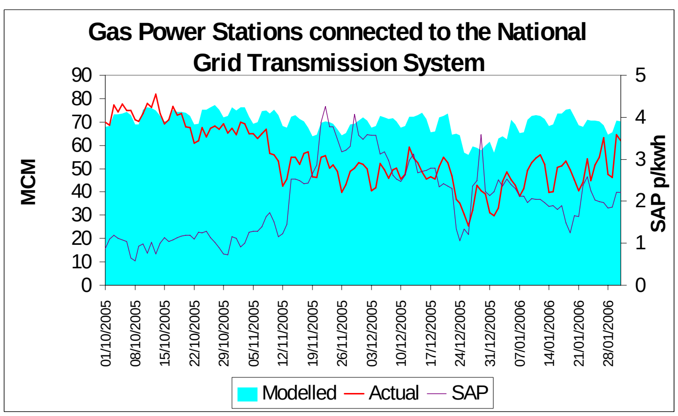

Figure 14: Power stations connected to the NTS - comparison of actual and forecast values

Source: NG, Demand response slide pack sent to Frontier

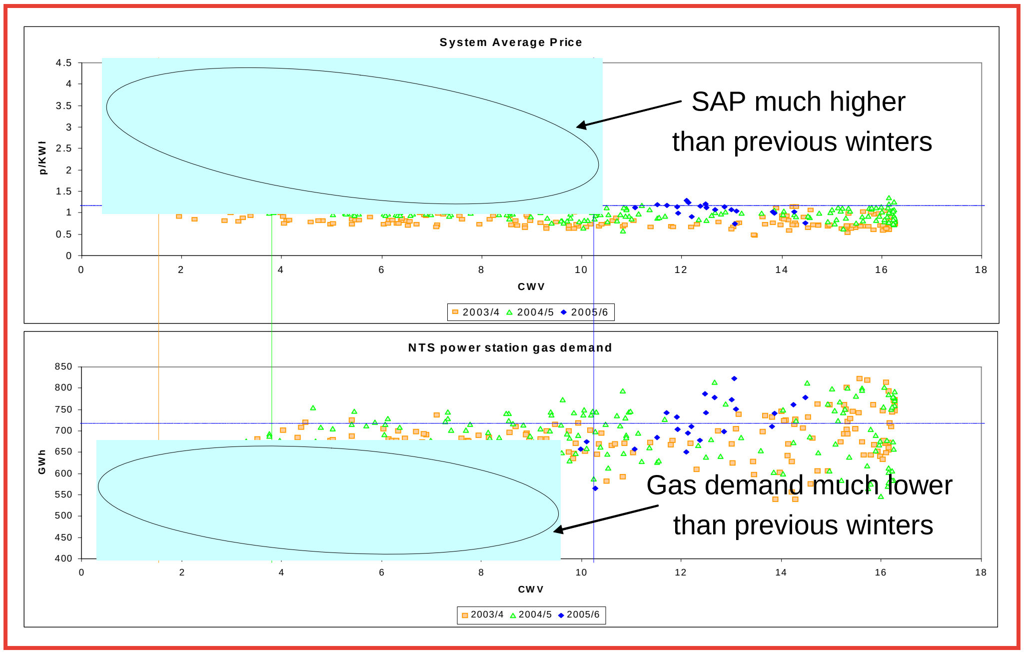

Figure 15: Price effects and power station demand

Source: NG, Demand response slide pack sent to Frontier

What this suggests is that when the demand and supply conditions prevailing are relatively lax (i.e. relatively plentiful supply relative to demand) then the 1 in 50 and 1 in 20 forecasts are likely to be reasonably accurate. If however, 1 in 50 or 1 in 20 conditions are also associated with a relatively tight supply-demand balance then prices can be expected to rise and to play a part in rationing demand. Since price responses are not a feature of the approach, then the forecast is more likely to be biased in an upward direction under such circumstances.

4.2 RECOMMENDATIONS

In our view, the principal causes of the recent forecast errors is that the forecasting process does not take account of a demand response by price sensitive customers to higher gas prices. The weather-correction and daily demand forecasting process appears to have worked satisfactorily in the past, and continues to do so for non-price sensitive customers.

Our principal recommendation, therefore, relates to augmenting the daily demand forecasts produced as part of this process, with an analysis of demand response to particular price levels. We discuss how this could be undertaken in the following section.

5 Further recommendations on development of the forecasts

5.1 INTRODUCTION

As we have already indicated, NG's daily modelling does not contain a demand-side response to higher prices from industrial customers and power generators. Consequently, it is difficult to assess whether the scale of demand response required to ensure demand-supply balance (as calculated by NG in its table 1 of the 2005/06 WOR) could not in any case be achieved as a rational demand response by customers, rather than requiring some forced curtailment of load. In principle it would seem sensible to take such a response into account when developing the 1 in 20 forecast, which is NG's planning standard.

Therefore, in this section we outline an approach to assessing demand response, and present a worked example based upon analysis of demand responses in the power generation and industrial sectors.

5.2 APPROACH TO ASSESSING DEMAND RESPONSE

In this section we consider how NG's approach could be augmented with an analysis of demand-side response to higher prices. For the purpose of the analysis reported in this section, this is presumed to occur amongst power station customers and industrial customers connected to both the LDZs and NTS. Figure 16 below shows the composition of total daily gas demand by demand type for each day of the year, based on the average LDC produced by NG.

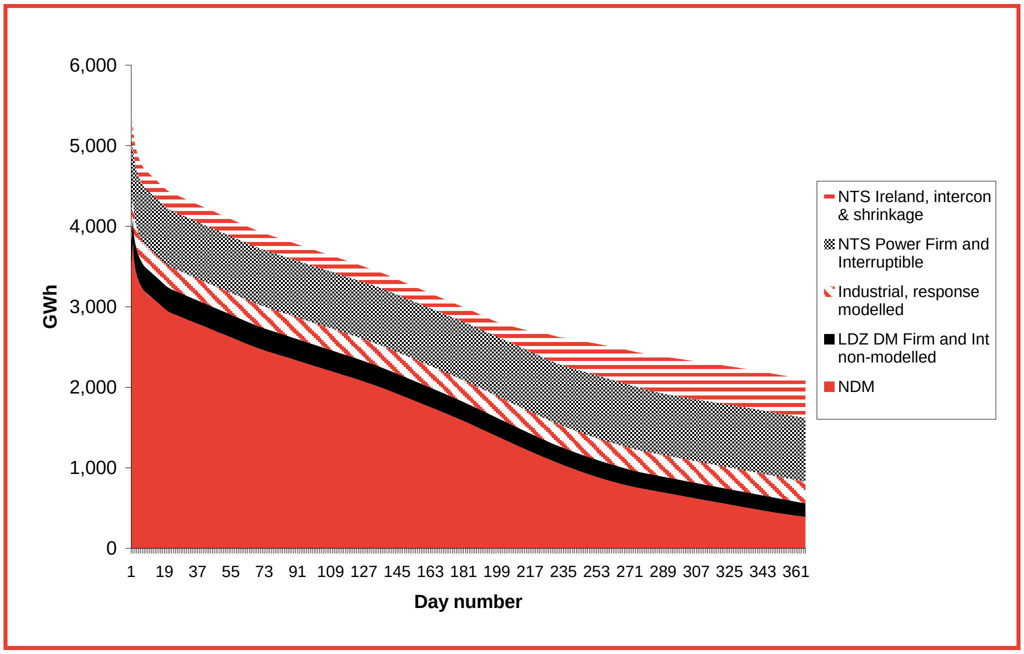

Figure 16: National average diversified LDC 2005/06, before demand response

Source: Frontier Economics based on data from NG

Figure 17 below shows a similar composition of total daily gas demand by demand type based on the 1 in 50 LDC.

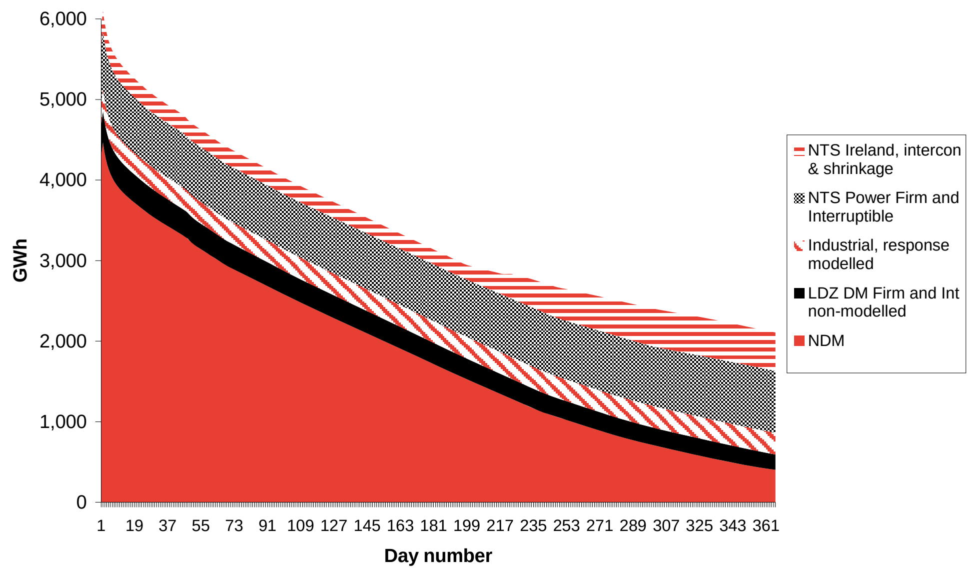

Figure 17: National 1 in 50 diversified LDC 2005/06, before demand response

Source: Frontier Economics based on data from NG

The key issue, which we now explore, is the extent to which the LDC for power stations and industrial customers can be affected by prices.

5.2.1 Power station demand for gas

Overview of the approach

Our approach to estimating gas demand from the power generation sector is centred on a simple, least cost marginal dispatch of available generating capacity. We presume that gas-fired stations will run if they are in merit (at full capacity if they are infra-marginal and partially loaded if they are the marginal unit on the system). This is the main driver of gas demand in the power sector, i.e. the decision on whether to run the station or otherwise. Since demand for electricity varies substantially over the course of the day, a station's gas demand will not be based on a simple binary decision for the day. A separate decision on whether to run can be taken in each half hour.

However, in addition to the decision on whether to run, some gas fired stations have the capacity to switch, for a limited time, onto distillate. When the price of gas rises above a certain level, which might vary from station to station, it will be cheaper and hence more profitable for the station to switch to its backup fuel. In these instances the station will still be delivering output, but will not be consuming gas.

In order to capture these effects, we have created a simple, half-hourly dispatch model of power plants in Great Britain. Our algorithm "stacks" power plants from cheapest to most expensive based on a range of assumed fossil fuel prices and plant efficiencies. The level of electricity demand in any given half hour can be compared to this stack in order to identify which stations are running. Given this simple dispatch pattern, it is straightforward to identify the total gas burn at different power stations. By varying the gas price we can identify gas demand for a range of possible gas prices, accounting fully for all fuel switching and running decisions. Annexe 1 provides the detailed description of data that we used in modelling power generation gas demand at different price levels.

National Grid has provided us with a list of CCGT power plants that have distillate stocks to hand, together with an estimate of how long such stocks might last. These plants generate using distillate when it economic to do so, but cannot do so indefinitely as stocks are limited. To capture this effect, we run three scenarios:

- Scenario 1: the first day of a cold spell, where all CCGT plants that could switch to distillate are permitted to do so if it is economic;
- Scenario 2: the seventh day of a cold spell, with all CCGT with stocks of distillate that would allow them to run for a week permitted to do so if it is economic; and
- Scenario 3: the fourteenth day of a cold spell, with all CCGT with stocks of distillate that would allow them to run for two weeks permitted to do so if it is economic.

Estimated price-demand relationship

We illustrate in Figure 18 the results of our analysis for the demand scenario without industrial demand response. The y-axis represents gas demand from power generators and the x-axis the range of gas prices.

Gas demand drops significantly over the region 22-31p/therm. At around this range of gas prices CCGTs become relatively more expensive than coal stations and cease running baseload. Gas demand is then relatively constant until approximately 75p/therm, the level at which it becomes economically profitable for stations to begin switching to distillate. As we would expect, the drop off in gas demand at this level is diminished in Scenarios 2 and 3, where fewer stations still have the capacity to switch to distillate. It should be noted that although the switch to distillate becomes economically profitable at about 75 pence per therm, in a situation when power plant managers expect even higher gas prices to prevail later in the year, they could maximise the gain from the switch to distillate if they can foresee correctly when the highest gas prices would be reached and use their [limited] stock of distillate in that period. In our demand response modelling we make an assumption of such perfect foresight; this is discussed further later in this section.

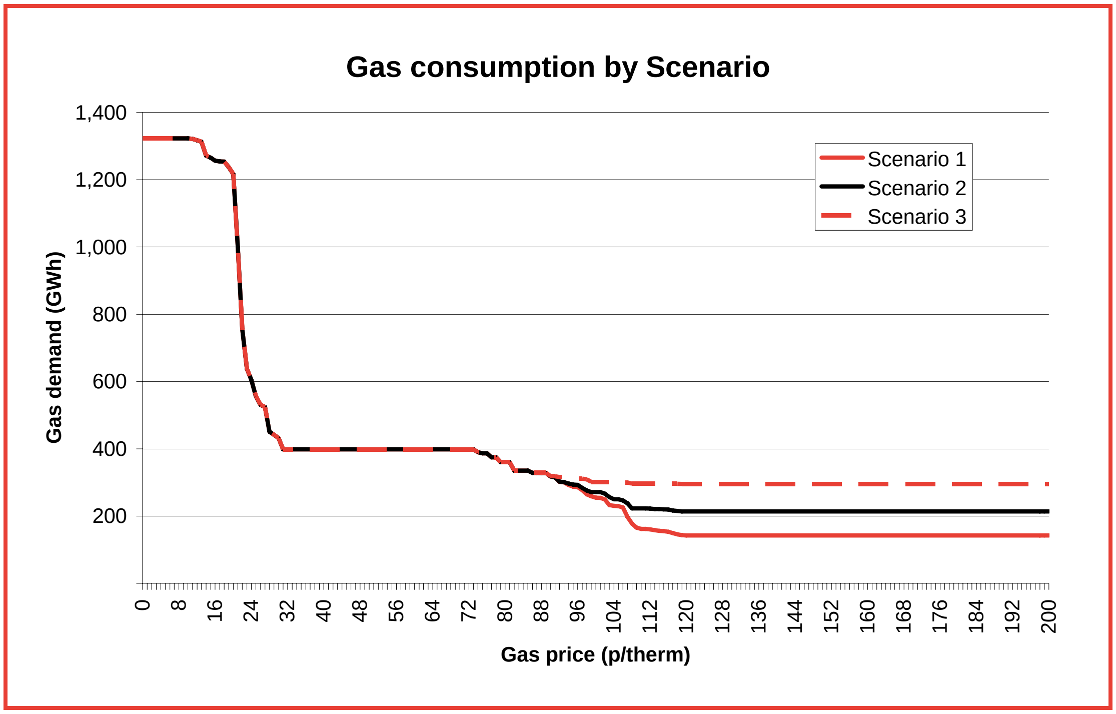

Figure 18: Gas demand from power generators for a peak demand of 64 GW

Source: Frontier Economics on the basis of various data

As gas prices increase electricity prices will also increase. At high gas prices this could lead to a demand response in the electricity sector. We have taken account of this in our modelling. In its report for Ofgem and the DTI, Global Insights[9] concluded that almost 1 GW of industrial load could be shed in the event of higher electricity prices and that the response could be higher still but for the protection from spot prices offered by existing contracts. We have assumed that a demand response leading to a load reduction of 1 GW would occur and that this response begins at 100p/therm and is complete at 300 p/therm. Once gas prices rise above 300 p/therm, we presume that a further 1 GW of load shedding is possible and that a full 2 GW demand response is evidence once gas prices rise to 500 p/therm. Beyond this level, we assume that there is no further demand response in electricity.

Figure 19 below shows the resulting central price-demand relationship that we obtained based on these assumptions.

9 Global Insights, *Estimation of Industrial Buyers' Potential Demand Response to Short Periods of High Gas and Electricity Prices,* Report for DTI and OFGEM, May 2005.

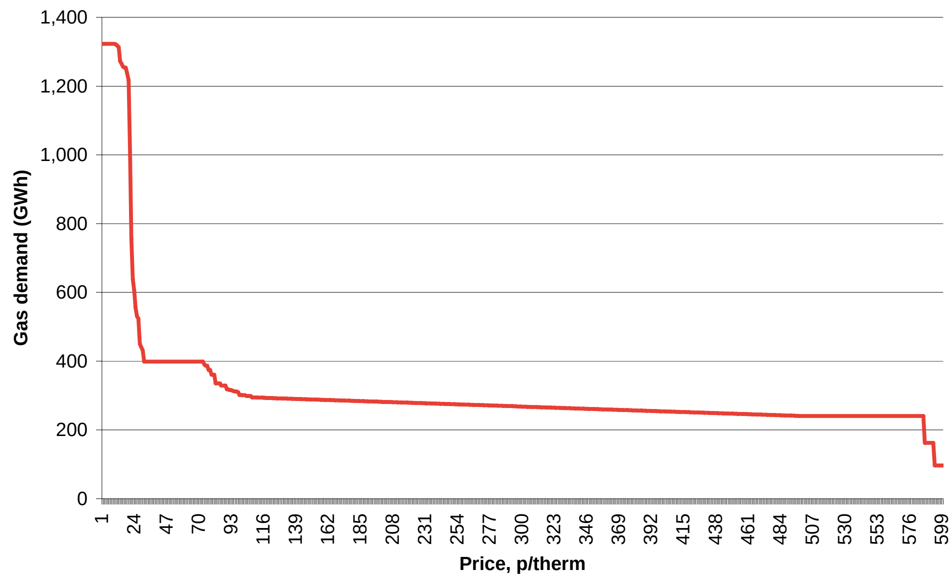

Figure 19: Daily gas demand from power generators at different price levels

Source: Frontier calculations

Impact of price on gas demand

Using the price-demand relationship shown in Figure 19 above, we estimated the impact of higher gas prices on the unrestricted gas demand from the power generation sector as calculated by National Grid.

As a hypothetical price schedule we used the actual daily prices of gas observed from 1 April 2005 to 31 March 2006, ordered from highest to lowest and applied in this order to the Load Duration Curves produced by NG. This implies that the hypothetical price schedule is perfectly correlated with demand, which may not necessarily be the case. However, any other relationship is likely to be equally arbitrary and also have the disadvantage that the resulting LDCs are difficult to interpret. For the purpose of simulating the effect of a price duration curve on demand, we do not therefore regard this approach as unreasonable. Figure 20 below shows the price duration curve.

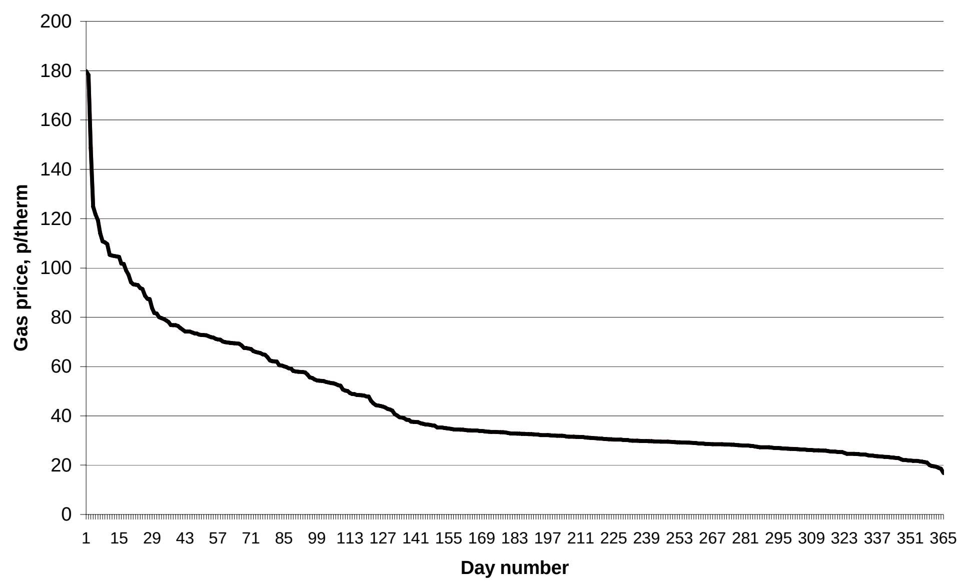

Figure 20: April 2005 - March 2006 actual price schedule used in demand response analysis

Source: NG, Frontier calculations

We also created a second hypothetical price schedule, where the lower half of the price duration curve is equal to the lower half of the 05/06 price duration curve, but the upper half is scaled up even further to simulate an even more extreme price response. The two hypothetical price duration curves are shown in Figure 21 for the purposes of comparison.

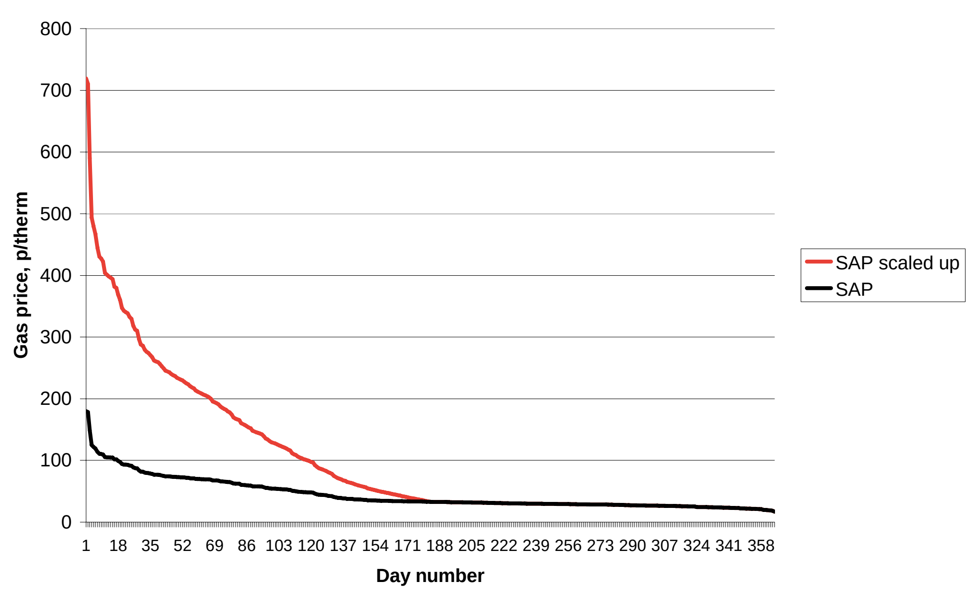

Figure 21: April 2005 – March 2006 actual and scaled up price schedules used in demand response analysis

Source: NG, Frontier calculations

Further recommendations on development of the forecasts

Figure 22 below shows the potential demand response to higher gas prices from the power generation sector based on the average LDC and the April 2005 - March 2006 price schedule[10].

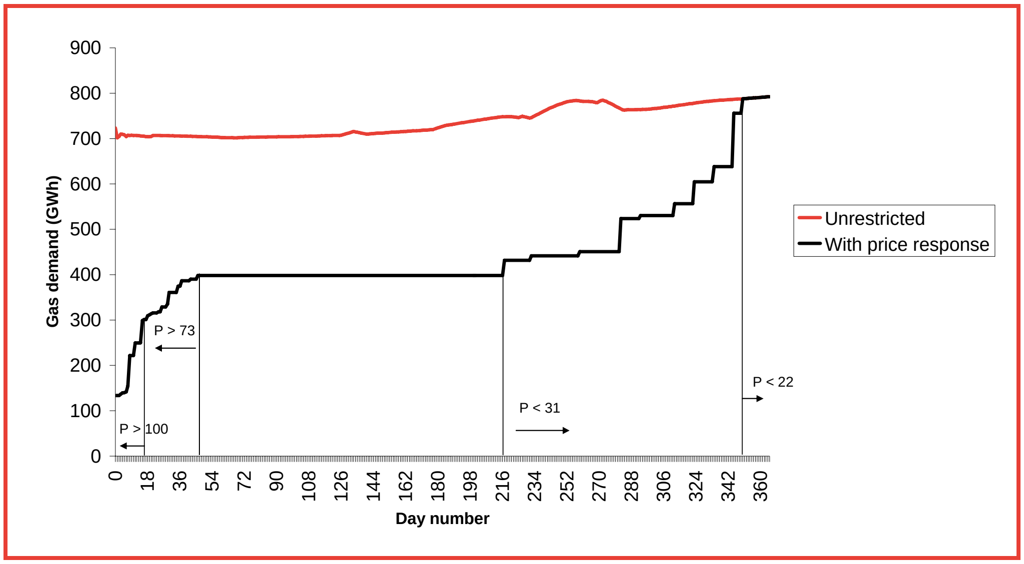

Figure 22: Demand response from power generation, average 05/06 LDC, April 2005 - March 2006 prices

Source: NG, Frontier calculations

Figure 23 below shows the potential demand response from the power generation sector based on the 1 in 50 LDC.

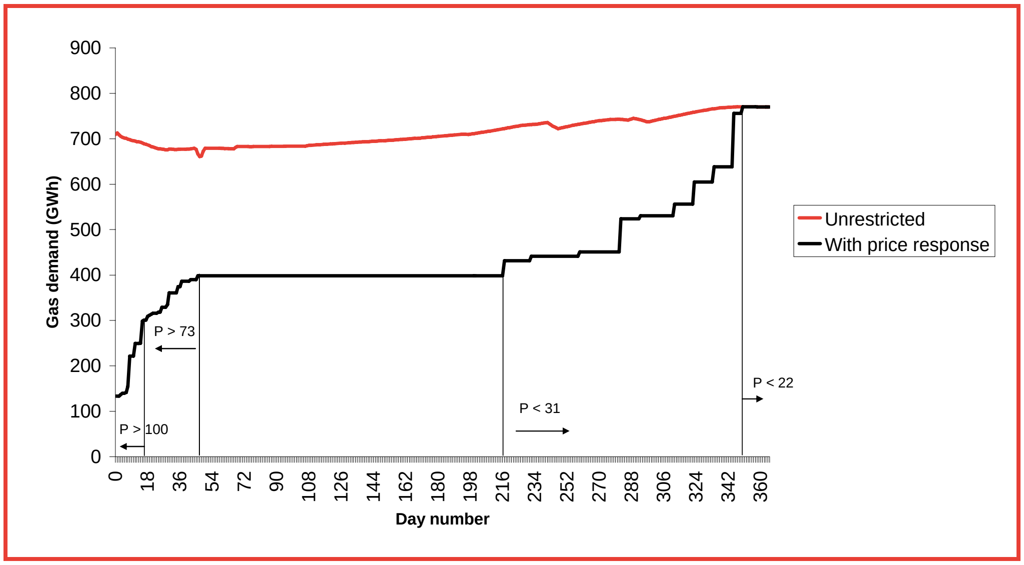

Figure 23: Demand response from power generation, 1 in 50 05/06 LDC, April 2005 - March 2006 prices

Source: NG, Frontier calculations

10 The response of the power generation sector to the scaled up prices is shown in Annexe 2.

As Figure 22 and Figure 23 show, power generation gas demand response is similar in the average and the 1 in 50 year. This is because the starting unrestricted gas demand is also similar in both cases, reflecting the fact that power generation gas demand is less sensitive to weather conditions.

The figures show that power generators operate in the unconstrained region (as calculated by NG) only at gas prices below around 22 pence per therm. At higher prices, demand response starts playing a role:

- as gas prices go up from 22 to 31 pence per therm, individual power stations switch from base to peak load, which is reflected in the step-wise shape of the load duration curve in this price range;
- at a gas price of about 30 pence per therm all CCGTs stations become relatively more expensive than coal stations and cease running baseload. From that point onward, gas demand remains stable until the price of gas reaches 75 pence per therm;
- at 75 pence per therm of gas stations that have considerable stocks of distillate start using those stocks, further reducing their demand for gas;
- at 100 pence per therm of gas, the high price of gas partially feeding through to the higher price of electricity triggers the start of an electricity demand response from large industrial electricity customers, and this again reduces the demand for gas; and finally; and
- in the first 14 and the first 7 days with the highest gas prices (in the April 2005 - March 2006 price schedule, these are 105 p/therm+ and 119 p/therm+, respectively), stations that have up to 2 weeks' and up to 1 week's supply of distillate begin using those supplies, which further reduces the demand for gas.

Quite clearly, the actual prices at which switching occurs may not be the same as estimated here. Additionally, we know that the demand response that actually occurred in 2005/06 did not go as far as the most extreme end of the range shown in Figure 22. However, this analysis has shown that the fundamentals of the relative prices of coal, gas and distillate could, and indeed did, provoke a significant demand-side response. In our view, this analysis of the fundamentals should form the basis for estimating the demand side response, which should then be augmented by information gathered by NG on technical and contractual factors that could limit the full extent of the potential demand side response being realised.

5.2.2 Industrial demand for gas

Overview of the approach

Large industrial customers can also be expected to reduce their consumption of gas in response to high gas prices, although the nature of the response in this case is more difficult to model accurately than in the power generation sector. This is because different industries and companies have:

- different and more varied technological requirements for gas, and correspondingly different scope for switching to other fuels and/or other raw materials;
- different shares of gas in the total costs, and correspondingly varying degrees of sensitivity to changes in the price of gas; and
- different types of customers and competitive environment, and correspondingly different scope for passing the higher cost of gas on to the final consumers.

In its study of the response of large industrial customer to higher gas and electricity price, Global Insights look in detail at the economic and technological determinants of the use of gas in each individual industry[11], and then derive their estimates of the total demand response from large industrial customers from those sector-specific studies. The Global Insights report calculates four types of gas demand response.

- *Theoretical*, which is estimated on the basis of a variable cost calculation to determine the break-even values of gas and power and also takes into account constraints such as commitments to customers or costs of stopping or restarting production. It assumes supply contracts which permit customer response to daily price movements[12].
- *Contractual*, which is otherwise the same as the theoretical response but also reflects the proportion of consumers whose gas contract does not give them any incentive to respond to spot market prices.
- *Hypothetical*, which is calculated by asking industrial energy managers how they would respond to gas prices of 100p or 500p per therm. Like the theoretical response, the hypothetical response assumes that all customers are exposed to spot market prices.
- *Empirical*, which is based on econometric analysis of actual industrial demand data from February and March 2005 (when there were 11 high price days in the range of 30p to 100p per therm) and extrapolation of the results of this analysis to prices of 100p and 200p per therm.

In our study, we rely on the Global Insights report and use it in two ways to inform our estimates of gas demand response from large industrial customers under different price and weather conditions:

- *first*, we use the theoretical, contractual, and hypothetical estimates as three separate demand response scenarios, and apply them to average and 1 in 50 LDCs under our two price duration curves; and

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11 The study analyses 15 industries: Glass, Ceramics, Bricks, Water, Cement or lime, Iron and Steel, Non-ferrous metals, Mineral products, Petroleum refining, Chemicals, Engineering, Food & Beverages, Textile & Leather, Paper & Printing, and Heavy Food.

12 Global Insights report, p. 2-3.

- *second*, we conduct our own empirical analysis using a larger and more recent dataset covering the period of 1 October 2005 to 31 March 2006, where gas prices above 30 pence per therm were observed in 165 out of the 182 days (with 17 days where price exceeded 100 pence per therm, reaching the maximum of 180 pence per therm on 14 March 2006). These estimates - which are discussed in detail in Annexe 1 - are in line with the contractual response schedule calculated by Global Insights.

Price-demand relationships

Figure 24 below shows the price-demand relationship for the industrial sector according to three response schedules as estimated by Global Insights: theoretical, contractual and hypothetical. Total unrestricted gas demand modelled by Global Insights covers 270 GWh per day. This is less than the total gas consumption by large industrial sites, which is around 400 GWh per day. This is because Global Insights excluded from their modelling sectors such as vehicle manufacturing and engineering, where energy use is significant in absolute terms but comprises only a small proportion of the total costs of the business[13].

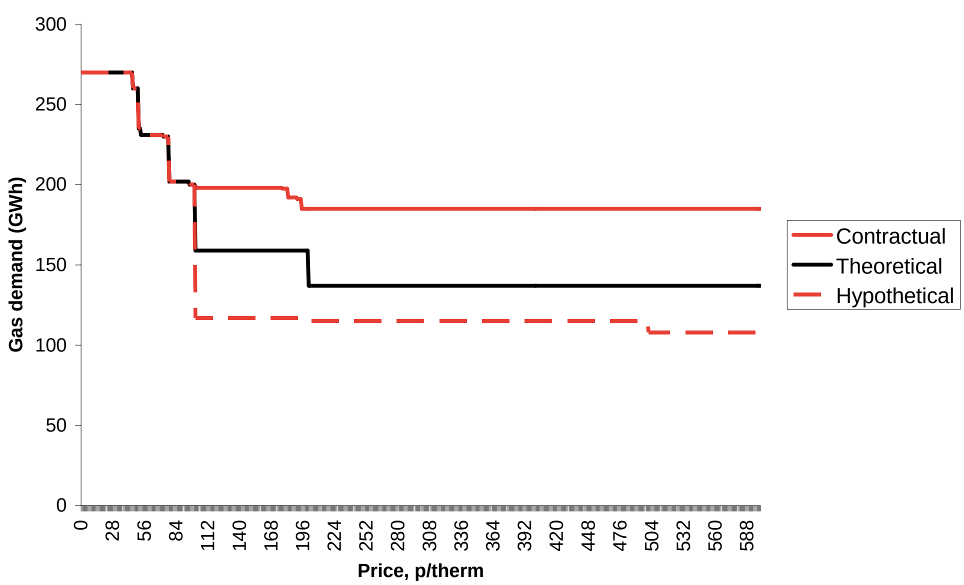

Figure 24: Gas price-demand relationship for large industrial customers according to three schedules estimated by Global Insights

Source: Global Insights Report, Figure 2-8 and Figure 2-4 in Appendix 1

13 Global Insights Report, p. 2-5.

Impact of price on gas demand

Using the price-demand relationships shown in Figure 24 above, we estimated the impact of higher gas prices on the unrestricted gas demand from the industrial sector as calculated by NG. Because the Global Insights report estimates this price-demand relationship only with respect to 270 GWh of daily gas demand by large industrial sites and we did not have access to the same detailed data to construct this aggregate precisely, we assumed that it includes all NTS Firm and Interruptible demand, plus a portion of the LDZ Interruptible demand that brings the total modelled demand to 270 GWh.

Using the hypothetical price schedule based on prices of gas observed from 1 April 2005 to 31 March 2006, Figure 25 below shows gas demand response by large industrial customers according to the three price-demand schedules presented in Figure 24. For the purposes of constructing the load duration curves later in this section, we choose to use the "contractual" curve when using the 2005/06 price duration curve as the basis for estimating the demand response, and the "hypothetical" schedule when evaluating the impact of the scaled up price scenario.

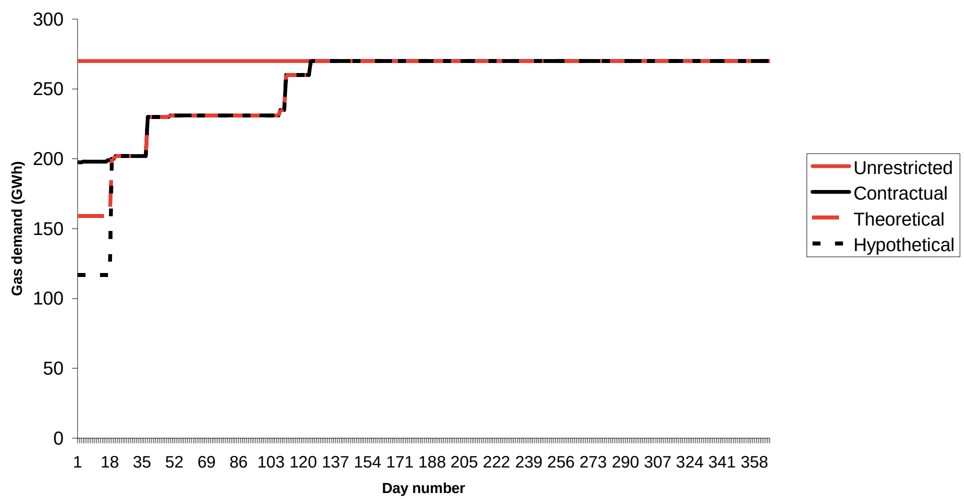

Figure 25: Demand response from the industrial sector (contractual, theoretical and hypothetical schedules), April 2005 – March 2006 prices

Source: NG, Global Insights, Frontier calculations

By way of comparison, Figure 26 shows the industrial demand response derived from the regression analysis we have undertaken on data between October 2005 and March 2006. The maximum level of response - around 100GWh - is similar to that derived from Global Insights contractual analysis, although the length of the response is a little longer.

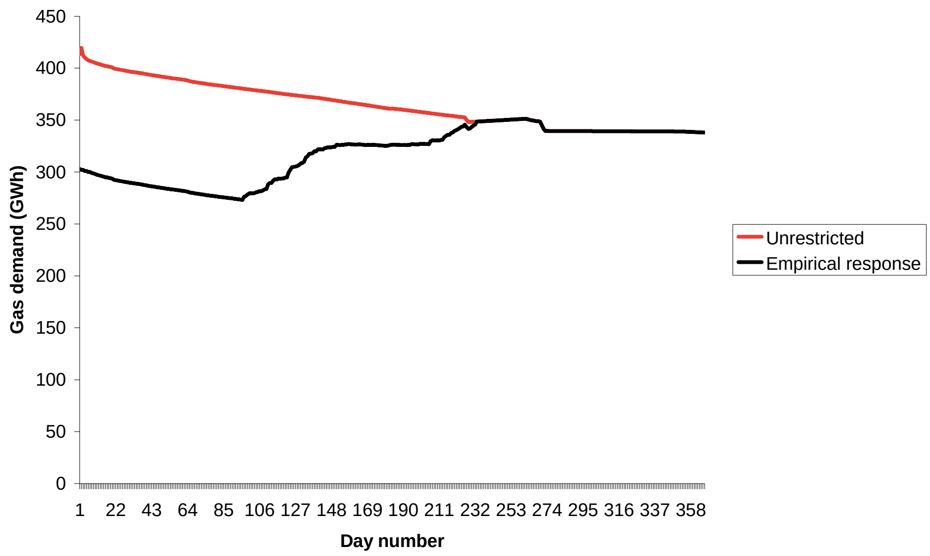

Figure 26: Industrial demand response to April 2005 – March 2006 price schedule, based on Frontier empirical analysis

Source: NG, Frontier calculations

5.2.3 Impact on aggregate demand

In this section we combine the demand response from the power generation sector and from the large industrial sector, to produce the total Load Duration Curves after the potential demand response. As in the previous sections, the charts below are based on the April 2005 - March 2006 price schedule. The full set of results based on the scaled up price schedule are provided in Annexe 2 of this report.

Figure 27 and Figure 28 shows the average 2005/06 LDC and the 1 in 50 2005/06 LDC respectively with the estimated demand response.

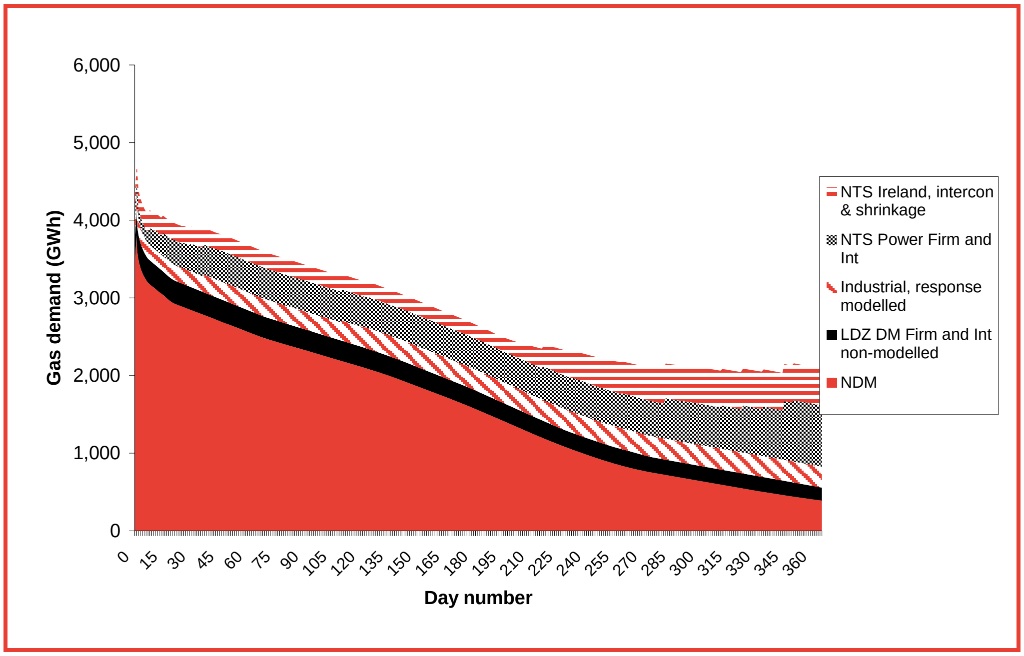

Figure 27: National average diversified LDC 2005/06, with potential demand response (April 2005-March 2006 prices, contractual response schedule for industrial customers)

Source: NG, Frontier calculations

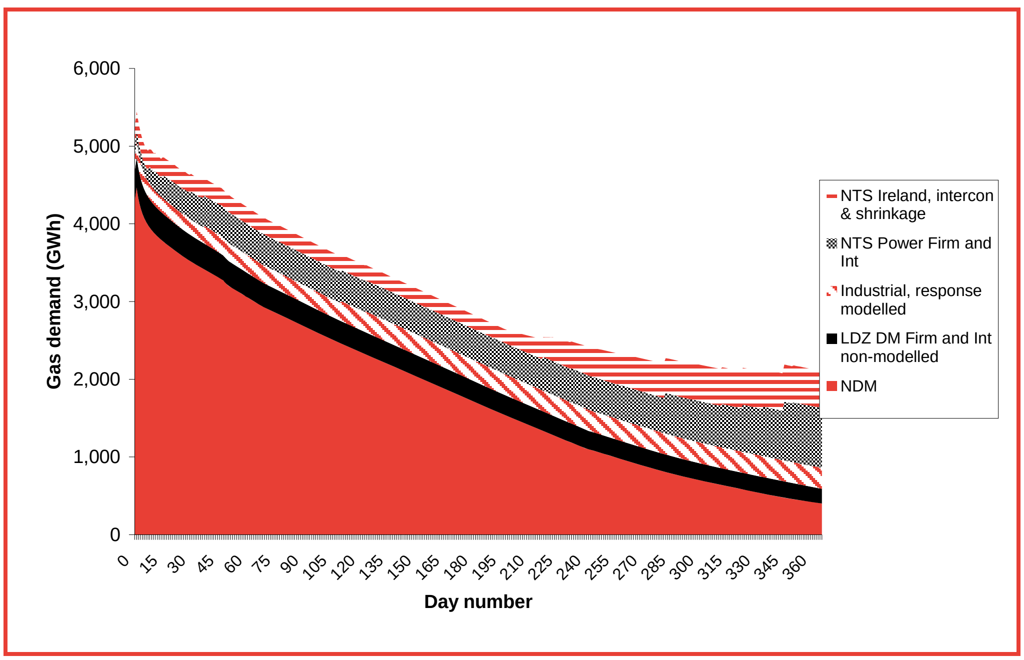

Figure 28: National 1 in 50 diversified LDC 2005/06, with potential demand response (April 2005-March 2006 prices, contractual response schedule for industrial customers)

Source: NG, Frontier calculations

Further recommendations on development of the forecasts

Figure 29 shows the total potential demand response to both the 2005/06 price duration curve and the scaled up price duration curve for an average weather year.

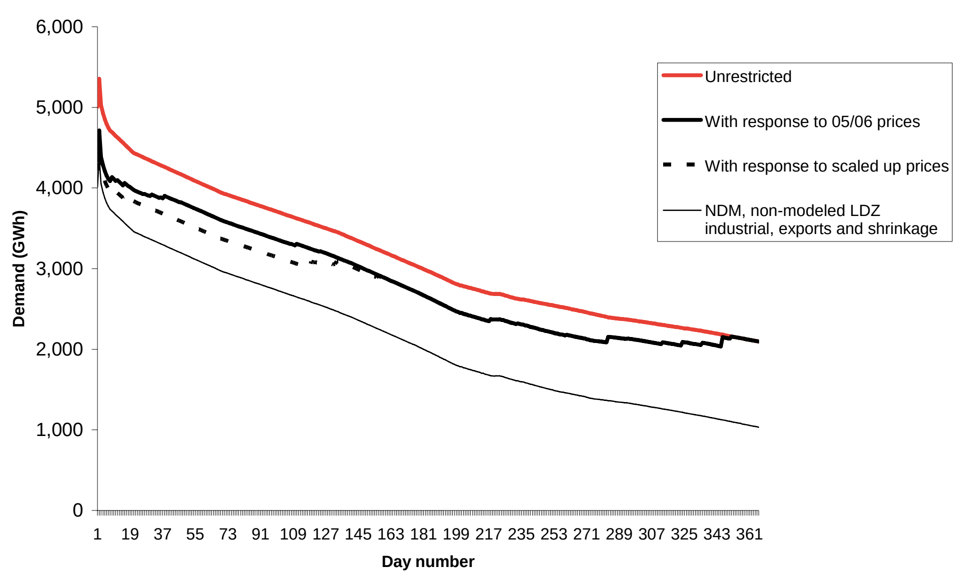

Figure 29: National average diversified LDC, unrestricted and with potential demand response

Source: NG, Frontier calculations

Figure 30 shows the total potential demand response to the 2005/06 price duration curve and scaled up price schedules for a 1 in 50 year. Again, the industrial response is modelled using the contractual schedule for the 05/06 prices, and the hypothetical schedule for the scaled up prices.

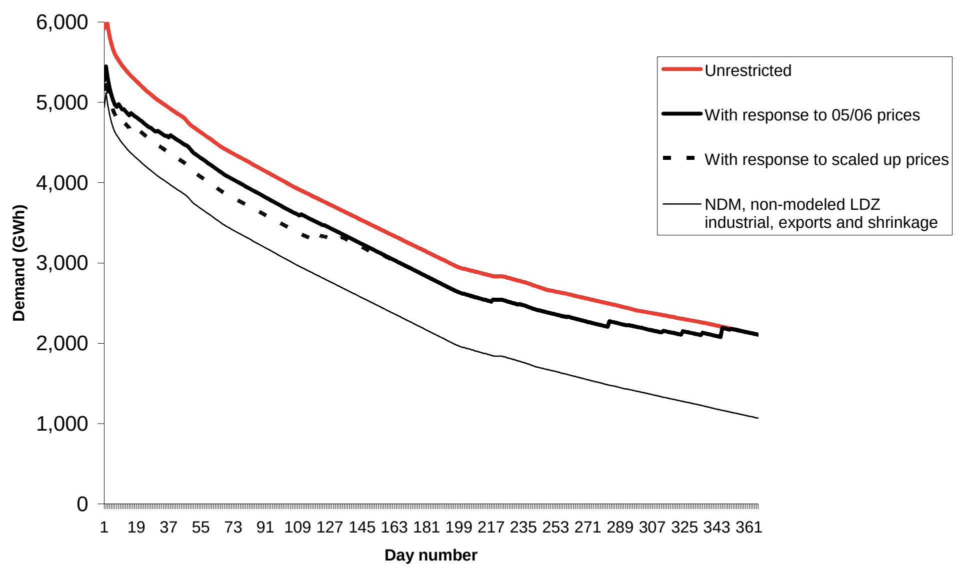

Figure 30: National 1 in 50 diversified LDC, unrestricted and with potential demand responses

Source: NG, Frontier calculations

5.2.4 Summary

In this section we have set out a methodology for developing an estimate of the demand response that might prevail given a set of gas prices that might arise. For power generation, it is based on the fundamentals of the relative prices of different fuels and generation technologies, which could be developed further with information on the constraints faced by operators that may prevent rational switching behaviour; and for industrial demand it is based upon the recent Global Insights report, supplemented by our own econometric analysis.

The results suggest that a significant demand response is possible under conditions of high gas prices, which could have the effect of mitigating the physical constraints that might apply in the event of supply or demand shocks.

In our view it would be informative to develop this analysis further as part of the finalisation of the WOR for 2006/07.

Annexe 1: Data and analysis underpinning the estimation of demand-side responses

DATA AND ASSUMPTIONS USED IN ESTIMATING POWER GENERATION GAS DEMAND

In this section we present the data that we used for the simple dispatch model described in Section 5.2.1 of the report.

- **Power generation data –** the asset register of generating plant (technology type, capacity and year of commissioning) used to support this exercise was taken from the 2005 Seven Year Statement. All assets included in this document that were installed by the end of 2005 were included. The coverage of the model is therefore Great Britain.
- **Power plant efficiencies -** We have used a database of plant efficiencies, by vintage, gathered by Frontier Economics from industry sources. This database has been tested and sense checked through use in numerous assignments. Where CCGT stations switch from gas to distillate, we have assumed a loss of efficiency of 5%. This is based on industry knowledge of the likely affect from previous assignments.
- **Power plant availabilities -** We assume that:
  - all thermal plants (nuclear, gas, coal and oil) run at maximum capacity (i.e. no outages);
  - all wind plants run at 35% of maximum capacity; and
  - all hydro plants run at 50% of maximum capacity (excluding pumped storage units where we made a demand side adjustment as described below).
- **Interconnectors –** We assume that the French-UK interconnector is importing at full capacity. We believe that this is a reasonable assumption.
- **Fuel costs -** We assume:
  - a carbon permit price of €25/t, broadly consistent with prevailing market prices;
  - a coal price of £36.07/t;[14]
  - a heavy fuel oil price of £262.24/t;[15]
  - a distillate price of £317.60/t;.[16] and
  - the gas price varies in our analysis.

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14 Dti March 2006 Quarterly Energy Prices - Average prices of fuels purchased by the major UK power producers and of gas at UK delivery points for Coal 2005.

15 Idem but for Heavy fuel oil 2005.

16 Dti March 2006 Quarterly Energy Prices - Prices of fuels purchased by manufacturing industry(1) Excluding the Climate Change Levy for Gas oil 2005.

- **Marginal cost estimates -** We assume that:
  - all nuclear, wind and hydro power plants run at a marginal cost of zero thereby making sure they are in merit; and
  - for gas, coal and heavy fuel oil plants we have used our fuel and carbon cost estimates and derived the relevant marginal fuel cost from our efficiency estimates.
- **Demand**
  - We have based our analysis on a typical winter day, calibrated to have a peak demand of 64 GW. This peak demand is consistent with the peak levels reported in the Winter Outlook.
  - In addition we model electricity demand response. We do this by reducing peak demand first from 64 GW to 63 GW, in line Global Insights expected maximum response, then from 63 GW to 62 GW, reflecting the higher response that might be possible in the absence of contract cover. This first demand response begins at gas prices above 100 p/therm and is complete at 300 p/therm. The second tranche of demand response begins at 300 p/therm and is complete at 500 p/therm. We assume that 2 GW is the maximum possible electricity demand response.
  - The profile for the day is based on data for the 3rd Wednesday in January, 2006.
  - We peak shaved the daily demand profile to take account of pumped-storage generation. For simplicity we assume that all pumped storage units in Great Britain generate during the 5 hours of highest demand each day.

ECONOMETRIC ANALYSIS OF INDUSTRIAL DEMAND RESPONSE

The Global Insights analysis

The authors of the Global Insights report cross check their theoretical, contractual and hypothetical industrial demand response estimates by carrying out econometric analysis of actual industrial demand data from February and March 2005 (when there were 11 high price days in the range of 30p to 100p per therm). The authors then extrapolate the results of this analysis to prices of 100p and 200p per therm.

The results of this analysis (figure 2-10 of the Global Insights report) are reproduced in Figure 31 below.

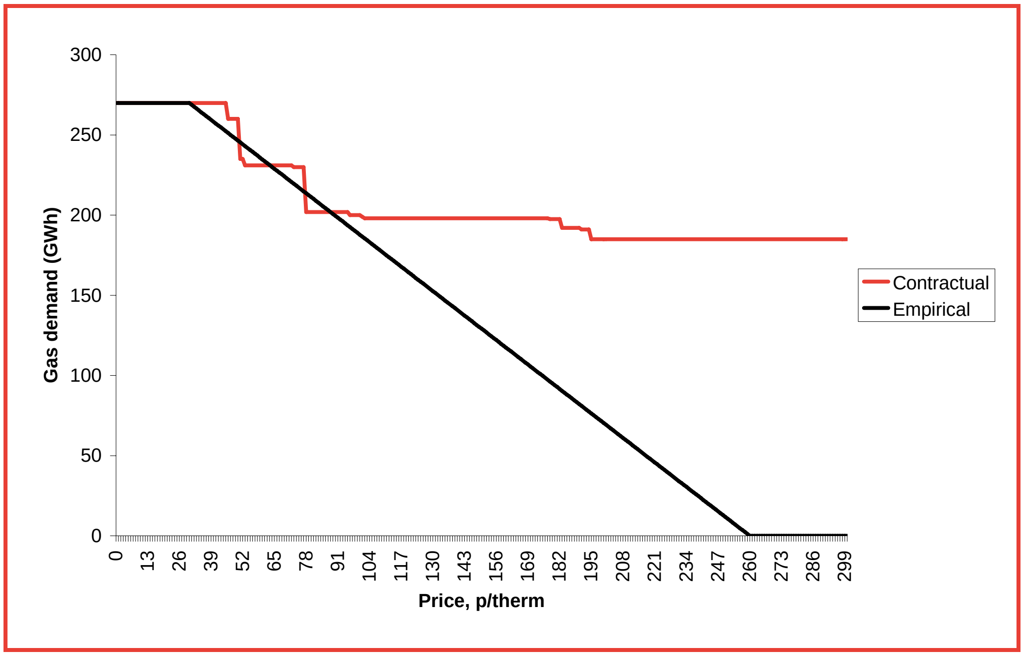

Figure 31: Price-demand relationship for large industrial customers, contractual vs. empirical

Source: Global Insights report, Figure 2-10

The report observes that, although their econometric analysis matches well the estimated contractual demand response in the segment of prices that were actually observed in their sample (up to 100 pence per therm), the relationship seems to be breaking down if extrapolated to higher prices. Consequently, the report concludes that it may not be appropriate to extrapolate the empirical results to higher prices, because there are contractual reasons to believe that at prices above 100 pence per therm industrial demand will be less sensitive to price increases than it was in the 30p – 100p/therm range.

Frontier analysis

In more recent data that is available, higher prices up to 180 pence per therm and the associated industrial demand levels are actually observed empirically. We used the data made available to us by NG, covering the period from 1 October 2005 to 31 March 2006, to try to re-estimate the empirical price-demand relationship. In this sample, gas prices above 30 pence per therm were observed in 165 out of the 182 days (with 17 days where price exceeded 100 pence per therm, reaching the maximum of 180 pence per therm on 14 March 2006).

We carried out empirical analysis of NTS interruptible and firm industrial demand, as well as LDZ daily metered interruptible demand. Figure 32 to Figure 34 below illustrates the relationship between price and demand over the period for the three load types. The clearest relationship between the two appears to be for NTS interruptible demand shown in Figure 32. The figure shows that as the price of gas increases from around 30 p/therm to about 40 p/therm, gas demand decreases substantially. However, further increases in the price of gas are no longer accompanied by similar reductions in gas demand. In fact, the demand appears to be not sensitive to price in the range of 40p/therm to 120 p/therm, fluctuating from 1 to 10 GWh per day for reasons seemingly unrelated to price. As prices break into even higher territory of above 120 p/therm, there appears to be a further stage of reduction in demand; however, with only three daily observations of such high prices, it is not possible to make any strong conclusions based on this evidence.

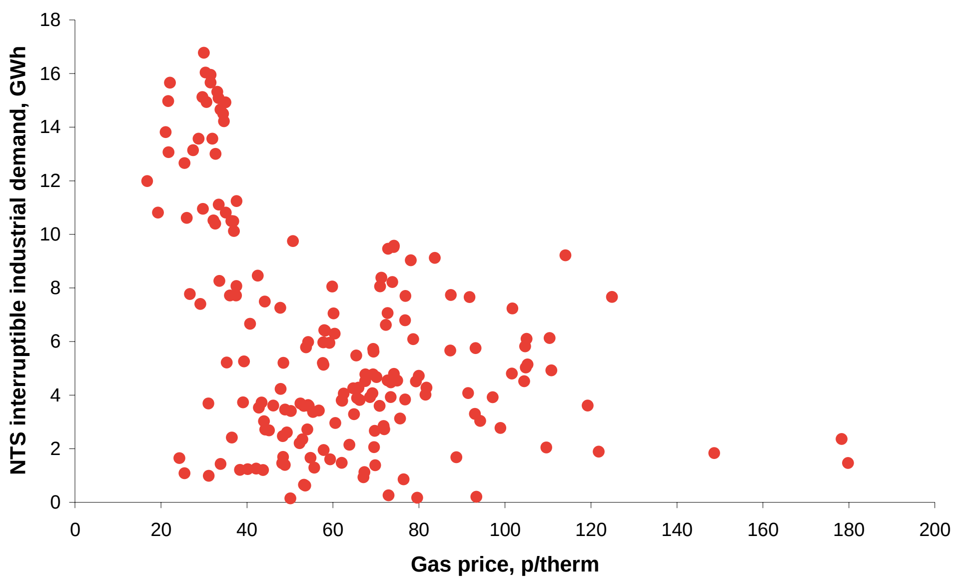

Figure 32: NTS daily interruptible industrial demand for gas and gas price (1 Oct 05 – 31 March 06)

Source: NG, Frontier calculations

The empirical relationship between industrial gas demand and gas prices generally is less clear for the other two components of total industrial demand, NTS firm and LDZ DM interruptible, as Figure 33 and Figure 34 shows.

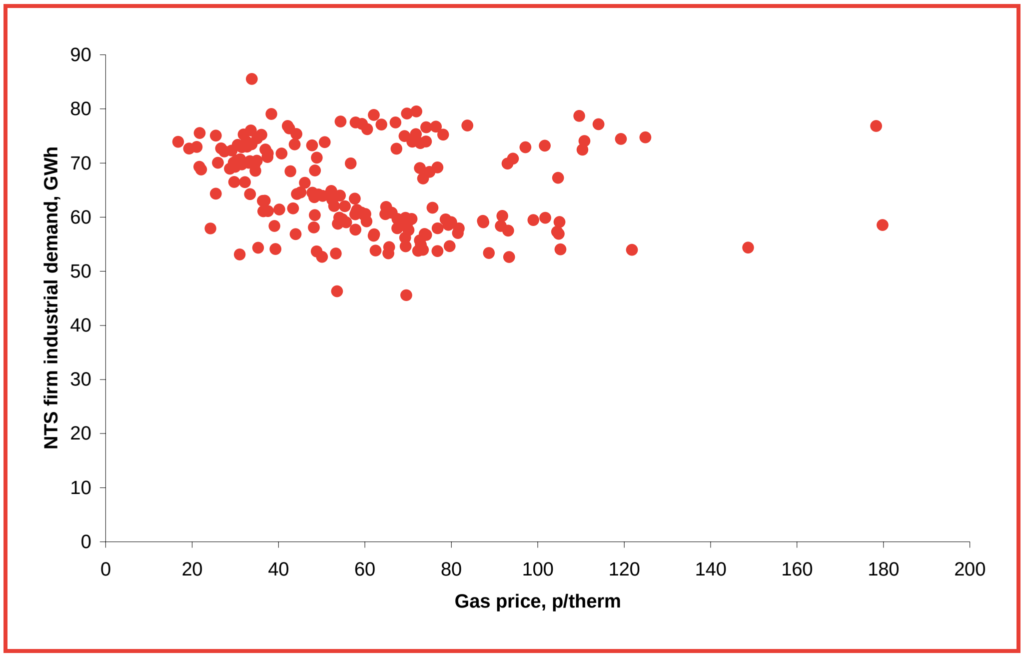

Figure 33: NTS daily firm industrial demand for gas and gas price (1 Oct 05 – 31 March 06)

Source: NG, Frontier calculations

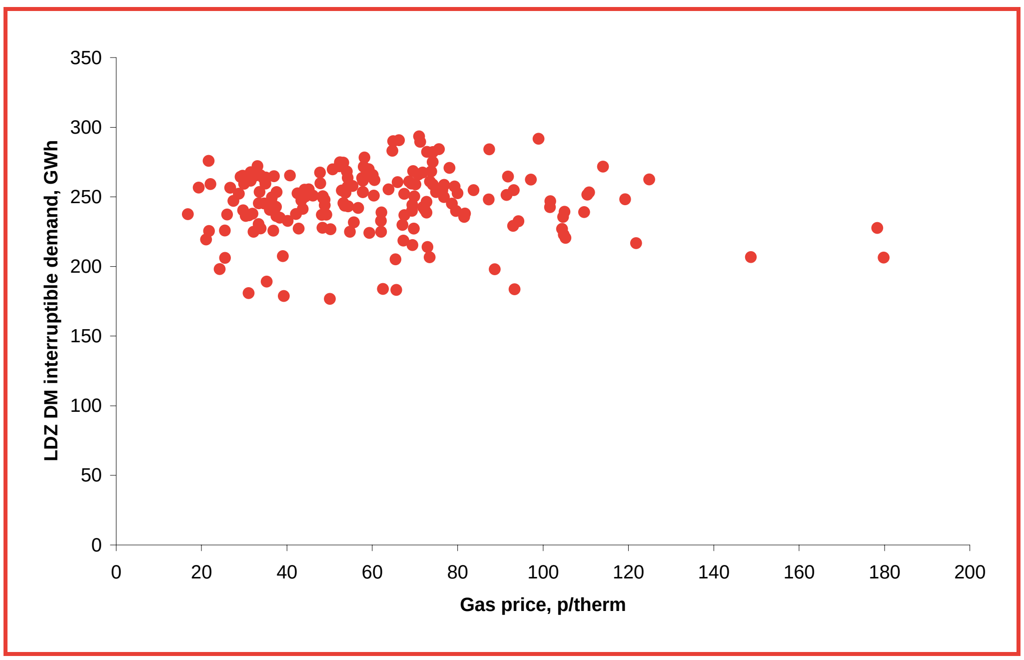

Figure 34: LDZ daily DM interruptible industrial demand for gas and gas price (1 Oct 05 – 31 March 06)

Source: NG, Frontier calculations

Annexe 1: Data and analysis underpinning the estimation of demand-side responses

These graphical impressions are confirmed by econometric analysis of the three load types, as shown in Table 15. The regressions were based on weekly data from 1 October 2005 to 31 March 2006 as a function of price (both in levels terms and at higher orders to capture any non-linearity[17]), the composite weather variable and a lagged dependent variable. Cells shaded in green contain coefficients significant at 1% level; cells shaded in yellow contain coefficients significant at 5% level; finally, cells shaded in light grey contain coefficients significant at 10% level. Subsequent sections provide the detailed results for each regression.

Demand type	Av. daily demand, MWh	R-sq	Coefficients						
			sap	sap^2	sap^3	sap^4	CWV	LDV	Const
NTS interruptible industrial	13	0.87	-14	0.31	-0.00	0.00	0.68	0.73	227
NTS firm Industrial	65	0.56	-0.80				-0.84	0.74	174
LDZ DM interruptible	247	0.53	-61	1.57	-0.02	0.00	16.30	0.67	1164

Table 15: Summary regression results, weekly data, regression with the CWV and LDV

The table illustrates that NTS interruptible demand (and to a lesser extent the other load categories) exhibits a clear relationship with price. However, despite this, it would be ambitious to use this analysis as the main source of evidence for estimating prospective demand response from industrial customers, for three main reasons:

- econometric models with higher-order polynomials are known for the risk of very different performance in and out of sample;
- even in the current sample of data this model performs well with the NTS interruptible industrial demand, but less so with the NTS firm and LDZ interruptible industrial demand (where price coefficients are significant but only at 10% level); and
- further, using such econometric models to calculate demand response from a given starting level of unrestricted demand requires knowing what price level that unrestricted demand corresponds to. The simulation results can be very sensitive to this assumption.

Accordingly, we use our empirical analysis to cross-check the price-demand relationship derived by Global Insights using operational modelling. We assume that unrestricted industrial demand components in the Load Duration Curves

17 These specifications were preferred to other specifications, including logarithmic specifications on the basis of diagnostic testing.

produced by NG correspond to the price of 30 p/therm (this is the level below which the price-demand relationship appears to discontinue, as illustrated, for example, in Figure 32). Under this assumption, we find that the total demand response of large industrial customers estimated using our empirical modelling (see Figure 35 below) is approximately in line with the demand response obtained using the contractual response schedule calculated by Global Insights, taking into account the difference in the scope of modelled unconstrained demand. In particular, our estimates show that demand remains stable for a relatively wide range of high gas prices, which is in line with what Global Insights calculate in their contractual response schedule[18].

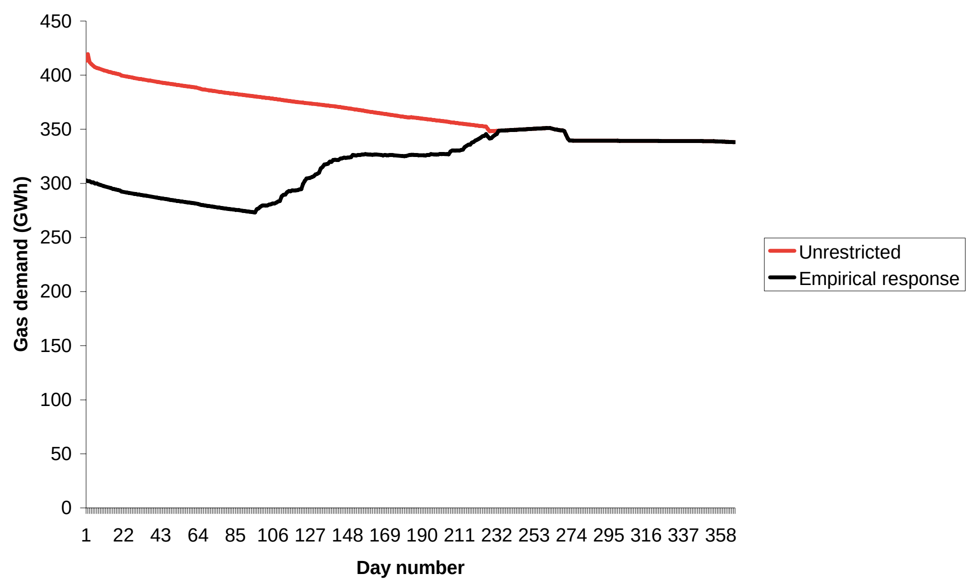

Figure 35: Industrial demand response to April 2005 – March 2006 price schedule, based on Frontier empirical analysis

Source: NG, Frontier calculations

18 Our empirical estimates also show a further significant reduction in demand at the very high gas prices (approaching 180 pence per therm), but this result is based on the evidence from only one data point with very high weekly gas price, and so cannot be treated as reliable. Because the effect may be exacerbated by the presence of a higher-order polynomial function of price in some of the underlying regression equations, we excluded this effect from the chart.

Annexe 1: Data and analysis underpinning the estimation of demand-side responses

Annexe 2: Results for the demand response under the high gas price scenario

In this section we report the results for the potential demand response for the scaled up prices schedules. The scaling was carried out as follows:

- the highest price (corresponding to the first day on the Load Duration Curve) was multiplied by four, bringing it up to £7.20 per therm;
- the price at day 182 and all subsequent days was left unchanged; and
- the price at days between day 1 and day 182 was multiplied by a factor calculated as a weighted average of 4 and 1, where the weights were determined by the relative position of the day between 1 and 182.

The resulting scaled up price schedule is shown in Figure 36 below.

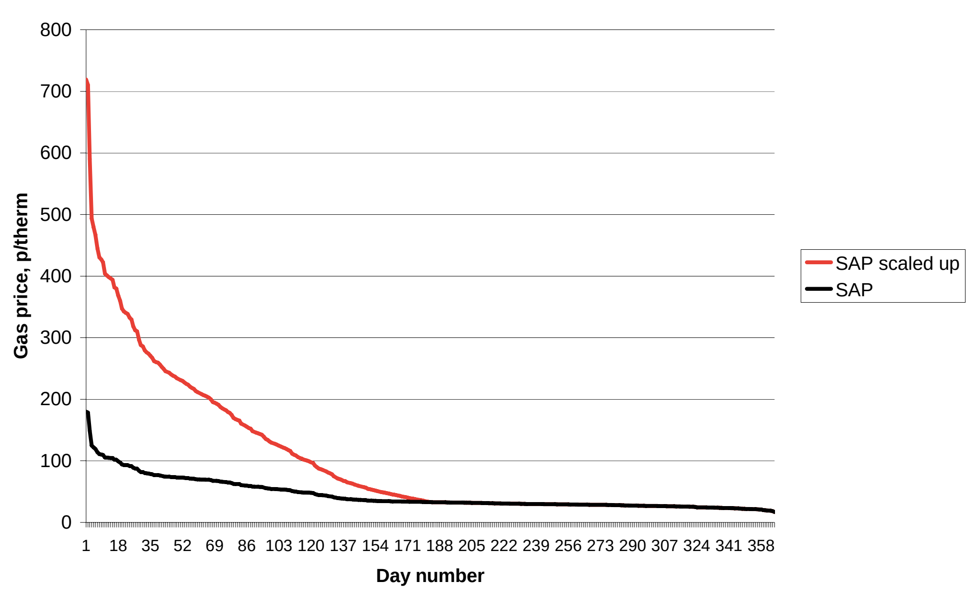

Figure 36: April 2005 – March 2006 actual and scaled up price schedules used in demand response analysis

Source: NG, Frontier calculations

Power generation sector

Figure 37 shows demand response of the power generation sector to the April 2005 to March 2006 and the scaled up price schedules, based on the average LDC.

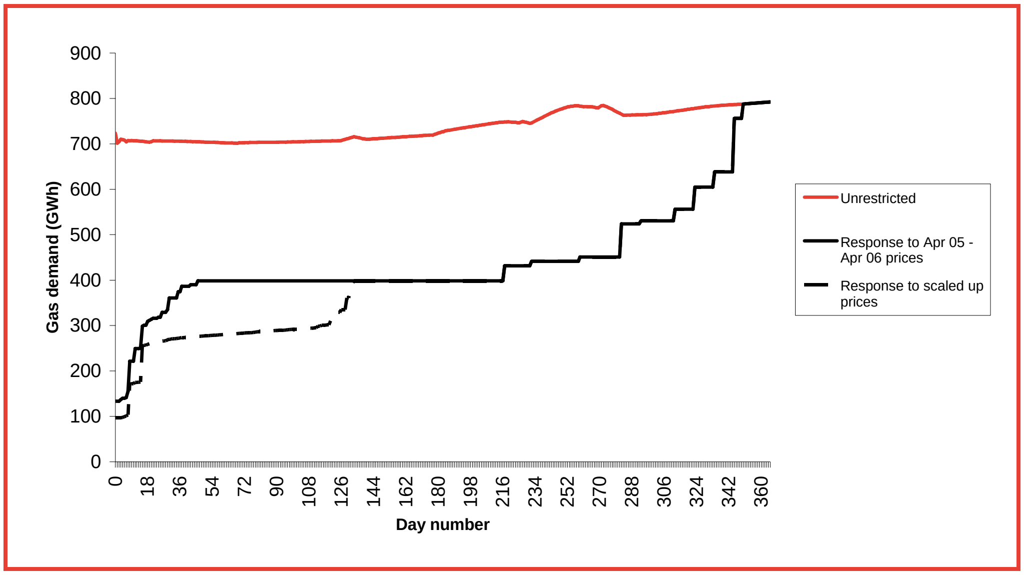

Figure 37: Demand response from power generation, average 05/06 LDC, April 2005 to March 2006 and scaled up price schedules

Source: NG, Frontier calculations

Figure 38 shows demand response of the power generation sector to the Apr 05 –Apr 06 and the scaled up price schedules, based on the 1 in 50 LDC.

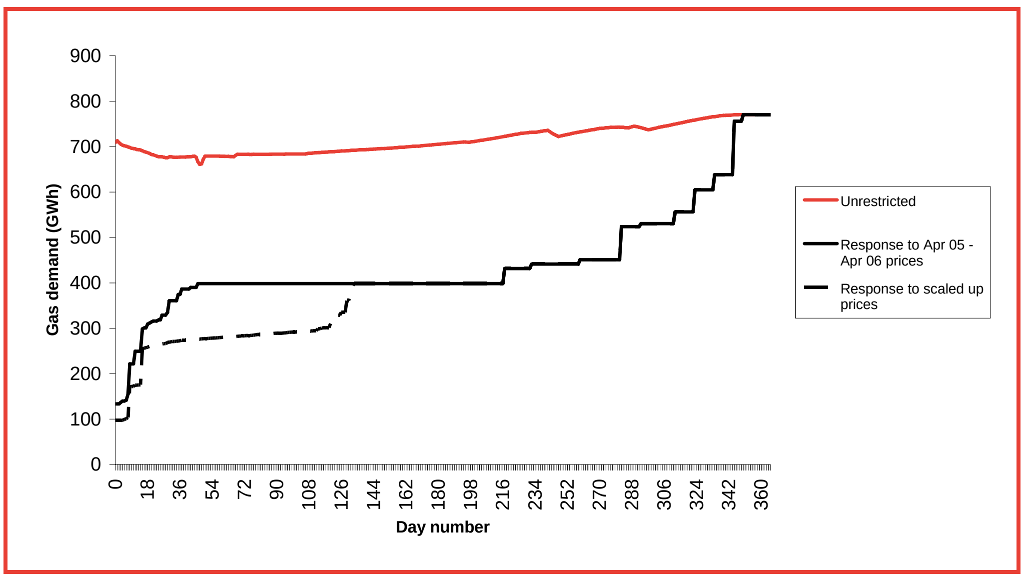

Figure 38: Demand response from power generation, 1 in 50 05/06 LDC, April 2005 – March 2006 and scaled up price schedules

Source: NG, Frontier calculations

Annexe 2: Results for the demand response under the high gas price scenario

Industrial sector

Figure 40 below shows demand response of large industrial companies to the scaled up price schedule. This figure applies to both average and 1 in 50 LDC[19].

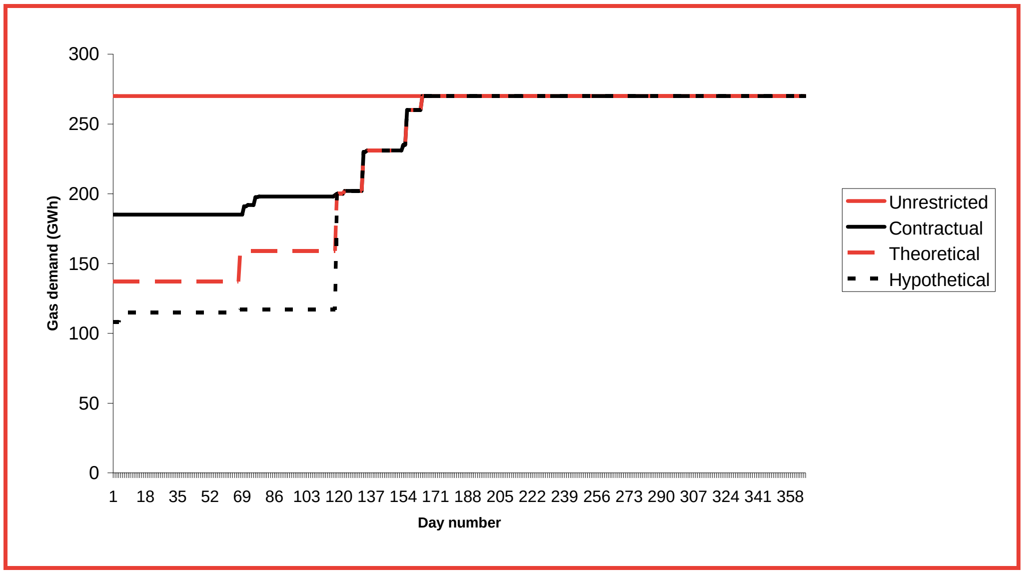

Figure 39: Demand response from the industrial sector (contractual, theoretical and hypothetical schedules), scaled up prices

Source: NG, Global Insights, Frontier calculations

Total LDC

Figure 40 shows the average 2005/06 LDC with demand response to the scaled up price schedule.

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19 This is because modelled industrial demand is in both cases capped at 270 GWh.

Annexe 2: Results for the demand response under the high gas price scenario

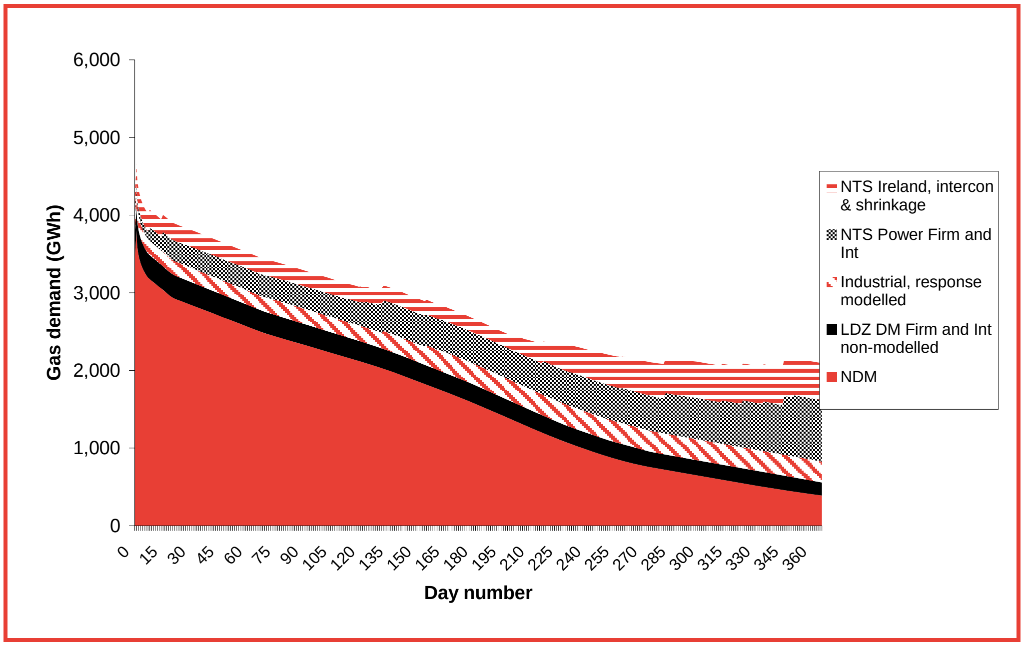

Figure 40: National average diversified LDC 2005/06, with demand response (scaled up prices, contractual response schedule for industrial customers)

Source: NG, Frontier calculations

Figure 41 shows the 1 in 50 2005/06 LDC with demand response to the scaled up price schedule.

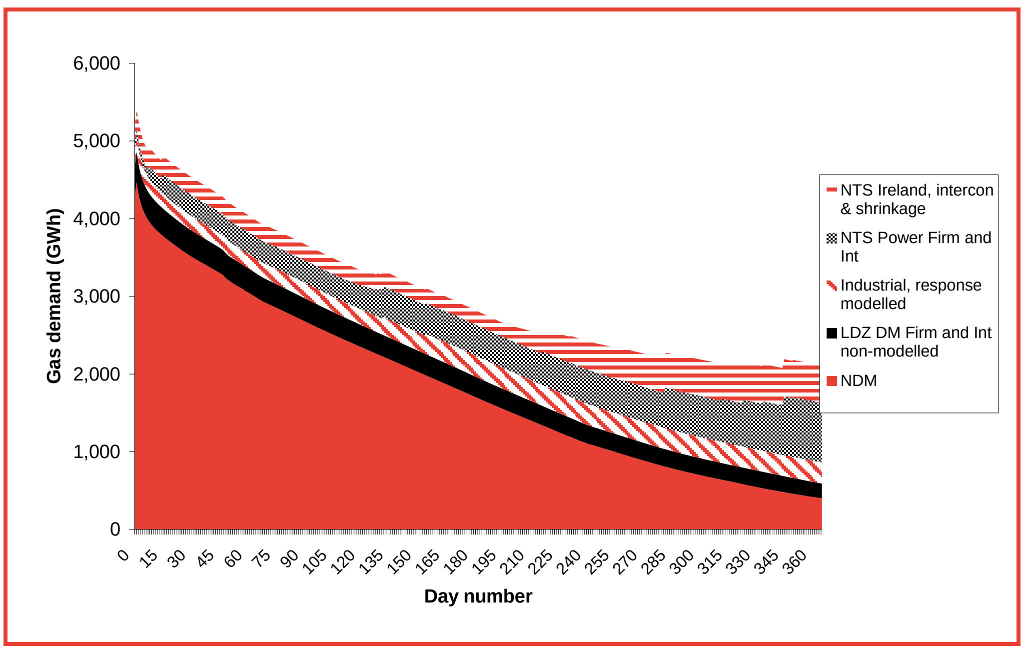

Figure 41: National 1 in 50 diversified LDC 2005/06, with demand response (scaled up prices, contractual response schedule for industrial customers)

Source: NG, Frontier calculations

Annexe 2: Results for the demand response under the high gas price scenario

Annexe 3: Day-ahead gas demand forecast

In addition to annual and peak gas demand/LDC forecasts, NG also produces a range of short-term forecasts: within-day, day-ahead and 2-7 day gas demand forecasts. Within NG, the day-ahead forecast is produced by a separate team, different from the team who work on the annual/peak forecasts. This Annexe provides an overview of the methodology used by NG in preparing such forecasts, focusing on the day-ahead modelling (methodologically the other short-term forecasts are very similar). While these short term forecasts play no role in supporting the Winter Outlook Report, Ofgem has asked us to review these forecasts in order to identify any common strengths and weaknesses that might exist in the different methodologies.

PURPOSE OF THE FORECAST

Day-ahead forecast produced by NG is used mainly for:

- internal consumption (system balancing), although this will clearly have an important impact on external users also;
- publication on NG's Information Exchange website and Gemini. to inform the market participants and shippers of likely demand; and
- in the case of LDZ demand forecast NDM demand allocation for shippers under Demand Attribution process in Gemini.

SCOPE OF THE FORECAST

An individual day-ahead gas demand forecast is produced for the 13 LDZs and for each NTS direct customer (i.e., for each separate power station, industrial load etc). This disaggregated structure of the forecast is driven by the way in which the results are used within NG for system management purposes. In addition, a shrinkage forecast is also produced. Total NTS demand is thus the sum of forecast LDZ and NTS direct demand and shrinkage.

The forecast is produced several times during the course of the day, with three particular forecasts being published on the NG website and distributed to other outside recipients in accordance with the UNC code and other obligations. In practice, we understand that at least three key forecasts are delivered to the website at 13:00 and 16:00 and 00.00.

METHOD OVERVIEW

The day-ahead team employs three different, complementary methods to produce gas forecasts:

- profile;
- regression; and
- Offtake Profile Notification (OPN).

The details of each method are described in the sections below. A different approach might be used for each site, depending on the historic performance of the different methodologies for the site in question.

Profile

This method consists of two steps:

- *first*, total end of day (EOD) demand for the day ahead (i.e., for the full next day) is forecast for the load site in question using a regression model (discussed below); and
- *second,* the forecast EOD demand is attributed to individual hours of the day using the weighted daily profiles of up to 7 days prior to the forecast day. In practice only the day before and 7 days ago are used.

Regression

In this method, day-ahead demand is forecast directly for each hour of the next day using separate regression models (i.e., 24 models for the full day).

OPN

The first two models are used to produce day-ahead forecast earlier in the day. By 17:00 (at the latest) each day, NG receives notifications from individual NTS customers about their expected gas usage next day. If information from OPNs is considered (on the basis of historical analysis) to be equally or more reliable than the forecast obtained by either of the first two methods, then NG at this point may switch to using OPNs directly as their main forecast.

REGRESSION MODELLING

In two of the three methods listed above (profile and regression) the key component of the method is regression analysis. NG uses the same general structure in the regressions that support both approaches (i.e. the daily total forecasts for profiling and the hourly demand forecasts for direct estimation without forecasting). Forecast gas demand (the left-hand side variable) is modelled as a function of:

- forecast composite weather variable (CWV);
- forecast effective and average temperature;
- today's demand plus demand of up to 14 days ago; and
- OPN if available by the time of modelling (from 17:00 at the latest).

Model coefficients are estimated on daily data, using data from the last 2 months and from the same 2 months a year ago. Model coefficients are re-estimated every week using the same specification. In addition, once every half year a larger modelling investigation is conducted, analysing whether some alternative model specification would perform better than the current model (e.g., including some additional variables etc)[20] and/or reassigning of different types of models as mentioned above.

As noted above, model design, testing and estimation is specific to each individual site, allowing the best approach to be adopted on a site by site basis. Forecasts obtained for each site are then aggregated to produce a forecast for NTS total day-ahead gas demand.

CHOICE OF THE FINAL RESULTS

Every half year, during a larger modelling investigation when NG reviews the specification of the regression models, they also compare performance of the first two methods (profile and regression) in order to identify which of the methods has the best performance. This choice of the best-performing model is done:

- by each hour of the day; and
- by each individual site.

Following such a review, while NG continues to produce forecast using all approaches, NG will make use of the model that showed the best performance in the biannual review exercise.

In addition, for those forecasts that take place later in the day (after around 17:00 when OPN numbers are available) NG may use the forecast based directly on OPNs, as they are regarded as reliable estimate.

Finally, the number obtained from the preferred model as described may be corrected by the operational staff in the NG control room, if they perceive a need to do so, based on their current operational knowledge of the system and prevailing gas market conditions. This number, after final review by the NG control room is the NG day-ahead forecast that is released to outside recipients, published on the NG website etc.

Again, as was mentioned earlier, all forecasts initially take place at the level of individual NTS sites. These individual forecasts are aggregated to form the total NTS day-ahead forecast.

FORECASTING PERFORMANCE

Table 16 below shows mean absolute errors (in percentage terms) of day-ahead 13.00 forecasts from January 2004 to March 2006, by quarter.

[20] We understand that NG is currently moving to conducting such a testing exercise on a quarterly basis.

	NTS Directs			LDZ			NTS Total		
Quarter	2004	2005	2006	2004	2005	2006	2004	2005	2006
1	7.7%	11.1%	12.6%	2.5%	2.5%	3.0%	2.1%	2.7%	3.5%
2	9.7%	13.2%		4.1%	3.4%		4.7%	5.7%	
3	9.4%	8.3%		2.6%	2.7%		5.4%	4.9%	
4	11.3%	12.0%		3.0%	3.2%		3.3%	3.6%	

Table 16: Mean absolute percentage error, day-ahead forecast

Source: NG

In the summer the main difficulty in predicting NTS direct demand is with forecasting gas storage injection and IUK flows, which is highly responsive to prices. In the winter, the main difficulty in the forecasting process shifts towards power station and weather uncertainties. As with estimating storage demand in the summer, forecasting power station demand is difficult as it may be more responsive to prevailing price levels. Weather will have a large impact on LDZ demand.

NEXT STEPS IN THE DEVELOPMENT OF THE METHOD

NG has shared with Frontier two key areas where they are aware of possible improvements to the methodology and which they expect to deal with in the future. These are:

- modelling of total demand and/or aggregated category demand; and
- data reliability.

In addition, Frontier believes that the current day-ahead forecast methodology would benefit from taking into account price information, for similar reasons to those set out in the main body of the report with regard to the forecasting work for the Winter Outlook Report.

We discuss these three potential development points in the sections below.

Modelling of category and/or total demand

The current day-ahead methodology takes a bottom-up approach to estimating NTS day-ahead demand, using regression and profile modelling for each individual off-take point. These individual forecasts are aggregated to obtain the total NTS demand forecast. Such an approach is driven by the way in which forecast results are currently used internally by NG for system balancing purposes.

While NG will continue to require such detailed analysis, this approach may not be ideal for forecasting NTS total demand, while it is the total demand that is likely to be of most interest to external users. This follows because individual regression forecasts may be subject to higher data noise than would be the case for a single aggregate forecast.

The NG team responsible for the day-ahead forecast is aware of this issue and aims to make a transition towards the aggregate NTS modelling. However, the process needs to be gradual, with the main constraint arising on the side of the users of the forecast, who will need to adjust their operational processes to be able to rely on the new format of the forecast. NG is working on this issue and expects implantation to require approximately one year.

Data reliability

This point is partially related to the previous one. Since demand modelling is carried out for each individual site, and since modelling needs to rely on data becoming available almost in real time (most recent numbers have to be used within hours of when they are received), checking for data errors becomes a crucial and a very large task. Given the frequency and detail of the data, a vast number of cross-checks are required. While much of this could be automated, there will always be a need for an intelligent assessment of whether data just received is reliable or otherwise and as a result data checking could develop into an extremely resource intensive exercise. NG is aware of the need for better checking of the data close to real time and is working to improve continuously the data due diligence process.

Using price information

In addition to the points discussed above, Frontier is of the view that NG day-ahead modelling process could benefit from the inclusion of price information in the list of parameters on which the forecast is based. The issues with day-ahead modelling are methodologically very similar to those discussed in detail in the main body of the report with respect to annual demand modelling and, as before, will be most relevant for modelling NTS demand. We do not reproduce the arguments or suggestions for improvement here, but refer the reader to the main text.

However, we note that any potential problem arising from the exclusion of prices from the current methodology is likely to be smaller in the case of day-ahead modelling. This is because the time span of the forecast is very short, and the evening versions of the forecast are in any event likely to rely primarily on the OPN numbers. OPN numbers will embody price signals, which implies that while the forecasts produced early in the day might be less reliable, this deficiency is unlikely to be long lived. Even with versions of the forecast produced earlier in the day, the issue is less critical as forecasts are always reviewed by the NG control room, who are aware of the current market conditions and would correct model predictions that are clearly out of line with the latest supply-demand conditions.

In summary, while there is still a case for the inclusion of price variables in NG's short term forecast, we do not regard this as an issue which is critical or urgent to resolve.

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