



Summer Outlook Report 2009

Executive Summary

1. Following the success of last year's Summer Outlook Report, National Grid has agreed to provide a detailed report into a range of issues that the electricity and gas industries may face during the summer months. This year the report has been extended to cover the period April to September.
2. This report covers potential electricity and gas issues, such as demand-supply balance, how demand responds to high temperatures, European interactions and transmission issues.
3. We have continued with a less formal process than that undertaken for the Winter Consultation Report. We welcome feedback on our analysis and the contents of the Summer Outlook Report to help us to ensure that it meets the needs of the industry in the future.

Electricity

4. The outlook for the electricity market in summer 2009 currently shows higher plant surpluses than at the same point in time before summer last year. The rare issues with electricity security of supply over recent summers have either been caused by exceptional events, such as exceptionally high levels of near coincident generation losses (May 27th 2008), or a period of warm temperatures with market response in making more generation available being lower than the higher demands observed at these times.
5. Market changes such as the introduction of the Large Combustion Plant Directive (LCPD) are behind us, but there is uncertainty over how some of the proposed market changes such as actions to reduce the cost of transmission constraints will impact summer operations. In the context of the inherent uncertainty faced, and presuming framework changes are at least neutral to security of supply, we continue to expect that demand should be able to be met in full provided that the electricity market continues to make plant available in response to the appropriate price signals.
6. On the demand side of our assessment of the summer outlook, clearly the biggest change for the coming summer from last summer is the impact of the recession. We anticipate continued recession impacts through the summer with demand on average reduced by 1.1 GW's.
7. Last summer we saw generation operating in line with market signals. One of the generation issues from summer last year was the non-availability of a large part of the nuclear fleet. Given that the units are

back in service, we have assumed that they will continue to operate at long term historic norm levels for the summer.

8. The Summer Outlook Report sections referring to electricity security of supply are based on market metrics that due to the dynamics of electricity balancing are regularly updated. The most up to date market information on expected plant surpluses and demand levels is provided on the key electricity operational information platform called the "Balancing Mechanism Reporting Service" at www.bmreports.com.

Gas

9. Summer demand levels for gas are typically half those experienced in the winter and therefore we are confident that demand will be met in all but exceptional circumstances. There is, however, considerable uncertainty on how supply will be utilised to meet demand. This is further compounded by annual maintenance to upstream supply infrastructure, the need to refill storage and the interaction of global and Continental markets through LNG and Interconnector (IUK) flows respectively.
10. We forecast a range of demands for each of the summer months. Weather affects are most noticeable during early and late summer, these are primarily limited to Non Daily Metered (NDM) demands. In aggregate, other demands are more stable through the summer though each demand component may at times be variable, notably power generation, storage injection and Interconnector (IUK) exports. The impact of the recession is anticipated to reduce NDM demand, we have assumed this reduction to be 6%, in line with our winter experience.
11. Together with NDM demand, gas demand for power generation makes up the largest demand component. Current forward prices for coal and gas suggest there is little to choose between coal and gas as the preferred source for power generation this summer. The operational restrictions on some coal plant through the LCPD could favour gas though the choice will remain marginal on most plant and be subject to changes to fuel prices, shipper generation portfolios and operational considerations.
12. The gas supply position this summer should provide adequate cover for the anticipated level of demands. The exception to this could be a major loss of supply infrastructure or high levels of concurrent upstream maintenance. Under these conditions we would anticipate an increase in the gas price thus providing incentives to attract additional supplies including gas from storage or even a reduction in gas demand through price sensitive demands such as IUK exports or gas for power generation.
13. In terms of supply sources we anticipate modest declines in gas from the UKCS being offset by additional volumes from Norway and possibly LNG where commissioning volumes from Milford Haven are now expected in the near future.

14. Compared to previous summers there is a lower level of NTS investment activity. This is reflected in our NTS maintenance plan that shows a high availability of entry capacity.

Industry Feedback

15. To help us improve the process for the Summer 2010 Outlook Report, we would appreciate any comments on this second report.
16. Responses should be e-mailed to energy.operations@uk.ngrid.com. Where requested, we will treat information provided to us on a confidential basis. However, respondents may send confidential information to Ofgem if they would prefer by e-mail to GB.markets@ofgem.gov.uk.
17. Unless specifically asked not to by respondents, we will share all feedback received with Ofgem. Respondents can request that their information is marked confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

Roles and Responsibilities

18. The competitive gas and electricity markets in Great Britain have developed substantially in recent years and have successfully established separate roles and responsibilities for the various market participants. In summary, the provision of gas and electricity to meet consumer demands and contracting for capacity in networks is the responsibility of suppliers and shippers. National Grid has two main responsibilities: first, as the primary transporter, for ensuring there is adequate and reliable network capacity to meet anticipated transportation requirements; second, as system operator of the transmission networks, for the residual balancing activity in both gas and electricity. The structure of the markets and the monitoring of companies' conduct within it are the responsibility of Ofgem, whilst the Department for Energy and Climate Change (DECC) has a role in setting the regulatory framework for the market.

Legal Notice

19. National Grid operates the electricity transmission network through its subsidiary National Grid Electricity Transmission plc and the gas transmission network through its subsidiary National Grid Gas plc. For the purpose of this report "National Grid" is used to cover both licensed entities, whereas in practice our activities and sharing of information are governed by the respective licences.
20. National Grid has prepared this consultation document in good faith, and has endeavoured to prepare this consultation document in a

manner which is, as far as reasonably possible, objective, using information collected and compiled by National Grid from users of the gas transportation and electricity transmission systems together with its own forecasts of the future development of those systems. While National Grid has not sought to mislead any person as to the contents of this consultation document, readers of this document should rely on their own information (and not on the information contained in this document) when determining their respective commercial positions. National Grid accepts no liability for any loss or damage incurred as a result of relying upon or using the information contained in this document.

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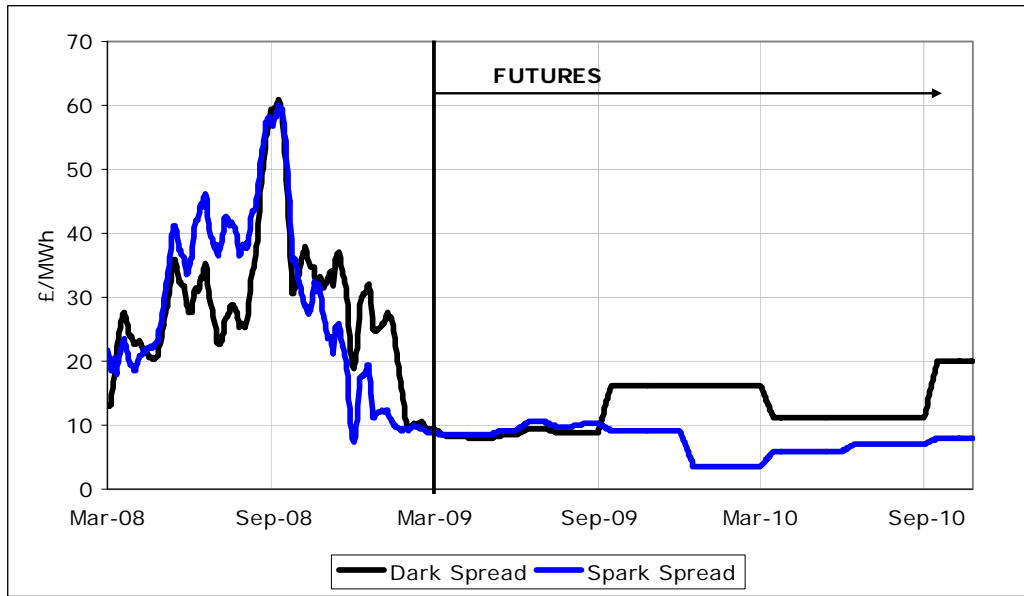
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Chapter 1: Electricity

Introduction

22. This Chapter focuses on the electricity supply-demand outlook for the forthcoming summer. Whilst demand levels are typically only around two thirds of those experienced in the winter, there tends to be a high level of generation unavailability during the summer, as power stations are shut down for maintenance.
23. Last summer the introduction of the Large Combustion Plant Directive (LCPD) and particularly some delays to the building of Flue Gas Desulphurisation (FGD) at some power stations led to a number of restrictions and outages last summer which will not be needed this summer. In addition, several nuclear power stations have returned from long duration outages in time for summer 2009 which should contribute to easing the facilitation of conventional plant outages.
24. The economic recession has contributed to lower demands than would otherwise have been forecast for the coming summer. A key metric we focus on for gaining a perspective on energy security of supply is the remainder value of declared available generation minus our reserve requirements and minus demand, which we term surplus. Taken together, the improved nuclear plant availability and lower demands are contributing to higher generation plant surpluses than last year.
25. Currently forward looking surpluses appear very comfortable, but of course this picture can and does change as we approach real time. The key operational uncertainty on the electricity demand forecasts used is the impact of the economic recession. We have limited frames of reference for how different phases of a recession impact demand because the last recession was almost 20 years ago and arguably the current recession in terms of global scale is something relatively unique.
26. On the generation side we foresee no issues under normal conditions given our assumption that the market responds to changes in demand by making generation available as required through market price signals.
27. Electricity prices and fuel costs for coal and gas for summer 2009 (see Figure E1 and Appendix 1) currently show that there is very little difference in gas and coal generation clean fuel spreads. At the start of March there was a small commercial advantage for gas fired generation, but so far over March we have seen this softening. If these circumstances prevail through the summer with finely balanced relative economics for coal and gas, then which power stations run will be driven more strongly by specific operational factors such as maintenance cycles and the generation portfolio position of station operators.

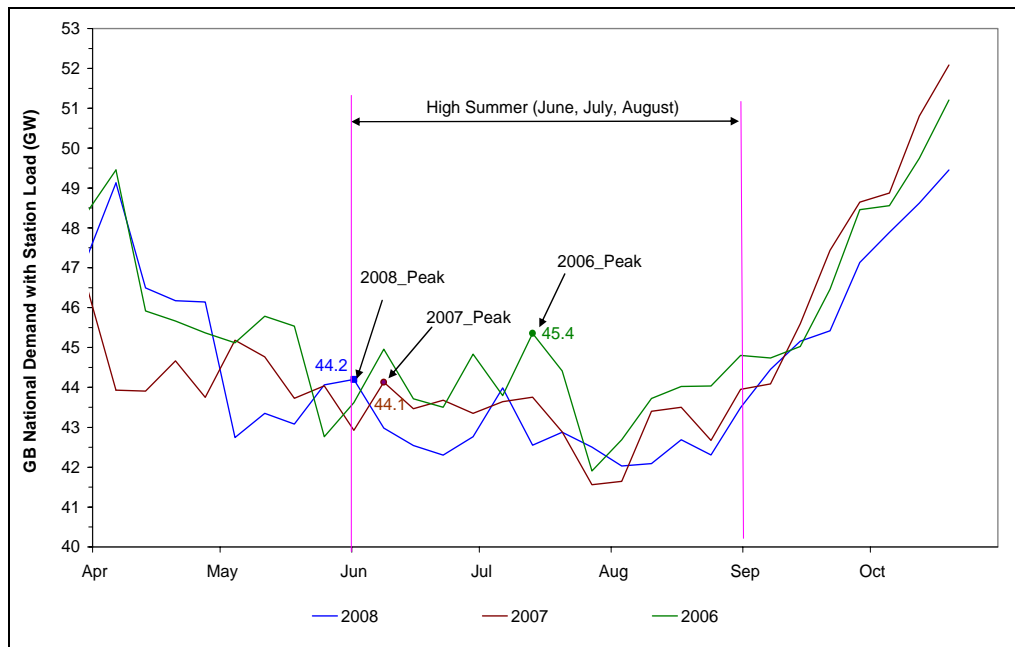
Figure E1 – Comparison of Dark Spread and Clean Spark Spread



Historic Summer Electricity Demand

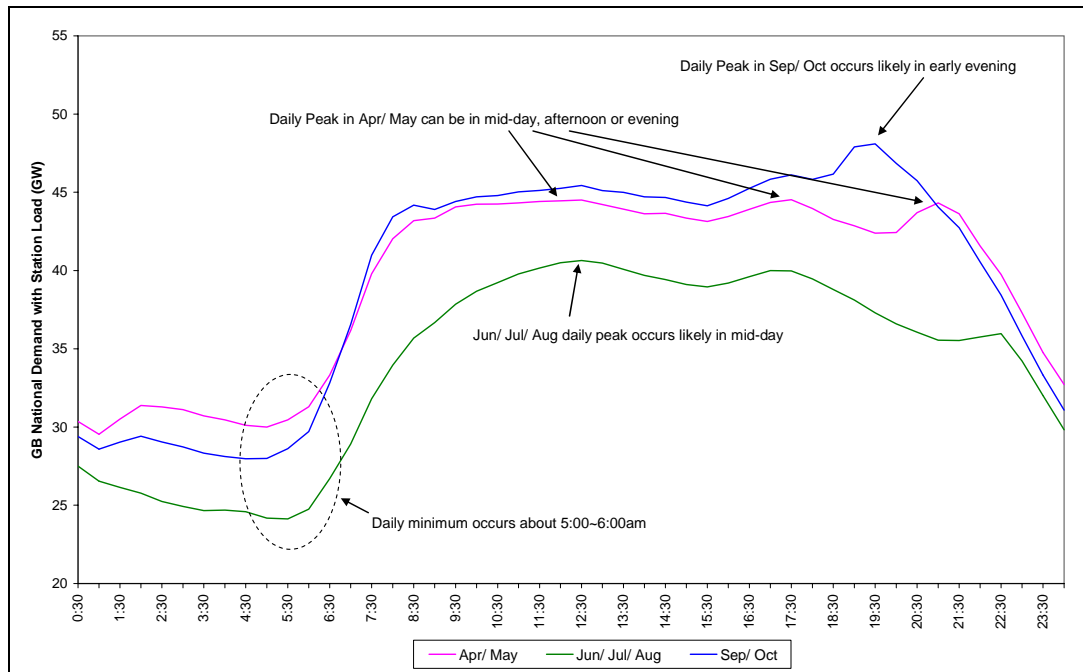
- 28. Unless otherwise stated, demand discussed in this report excludes any exports to France and Northern Ireland. There is discussion of exports to France and Northern Ireland later in this chapter.
- 29. Figure E 2 shows the weekly peak demand for the last 3 summers. The graph highlights the lower demand during “high summer” months (June, July and August) when the weather is generally warmer and brighter. Furthermore, minimum demand generally occurred in late July or early August when many people are on holiday.

Figure E 2 – Weekly Peak Demand of Last 3 Summers



30. Figure E 3 depicts the daily demand profile of summer months. In “high summer” months of June, July and August demand is reasonably flat across the working day (9:00 to 18:00), with a strong tendency to peak at midday. During April and May, demand is also reasonably flat across the working day, but there is a higher chance that demand will peak in the late afternoon, dependent upon the weather conditions. In the shoulder months of September and October the daily peak occurs in the evening, due to the effect of darker evenings increasing the lighting load. Daily minimum generally occurs around 5:00~6:00am.

Figure E 3 – Half-Hourly Demand Profiles



Interconnector Exports to France

31. Historically, across the summer there has been a varying profile of import/export flows on the GB-France Interconnector across the day. Last summer there was more import than the previous two years as illustrated in Figure E 4 and Figure E 5. The average import over the summer at weekly peak in 2008 increased by nearly 0.8GW compared to the two summers before.

Figure E 4 – French flows at time of TSD Weekly Peak Demand

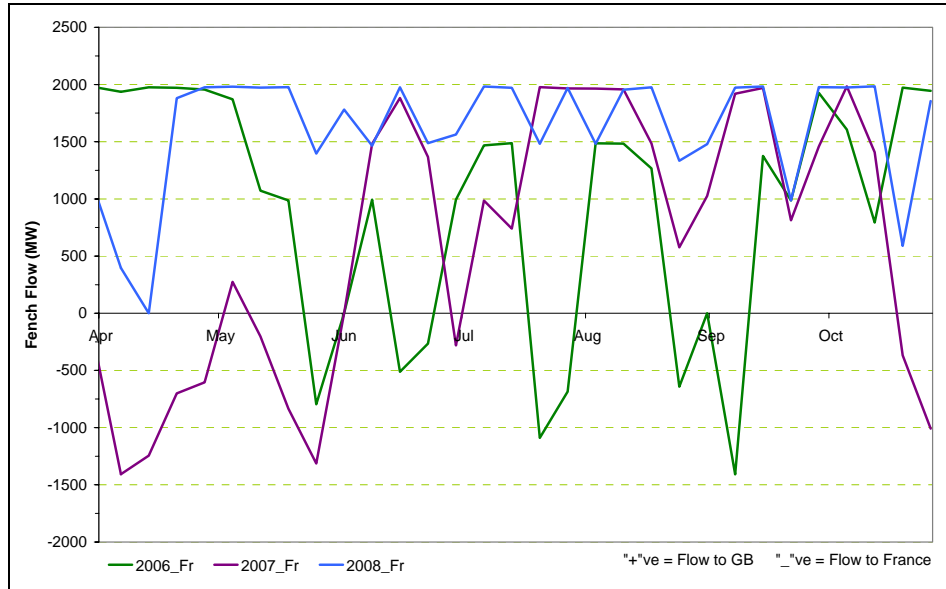
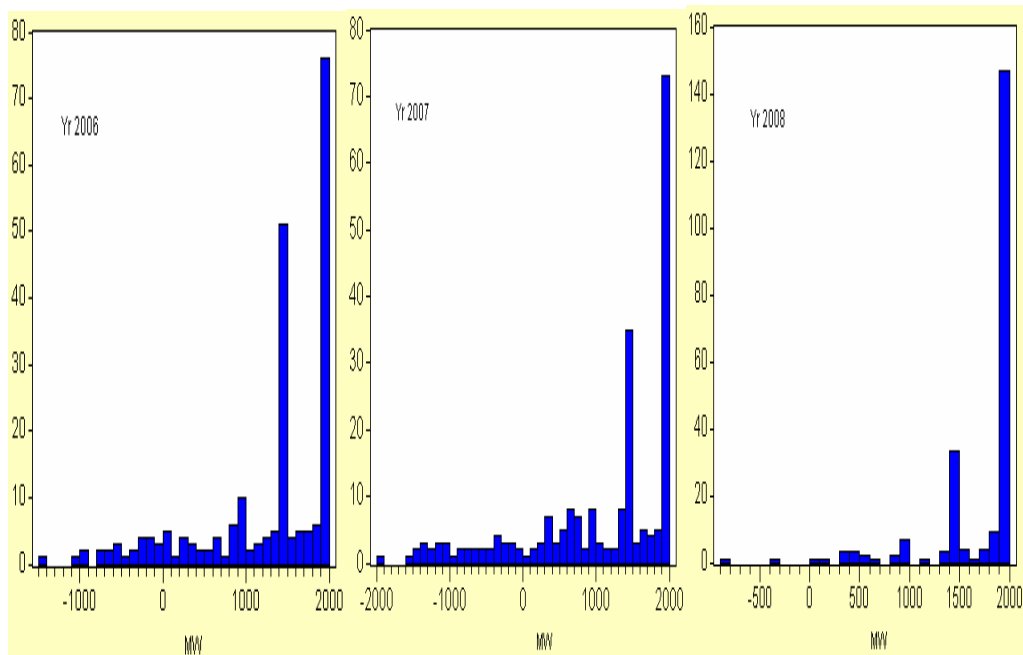
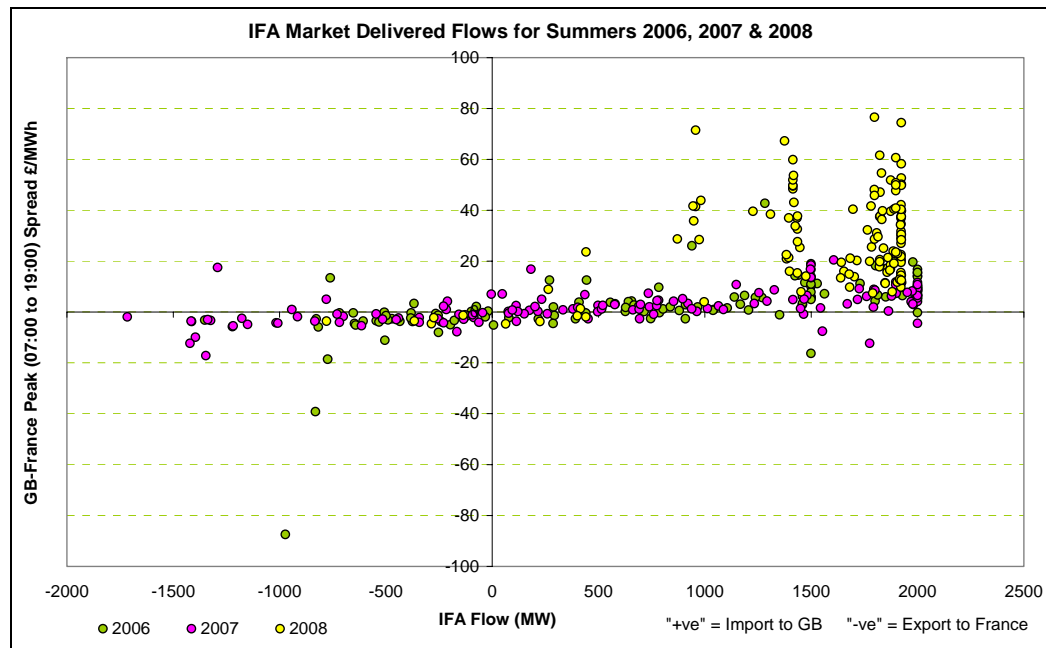


Figure E 5 – Frequency of French Import/Export at time of Daily Demand Peak



32. Figure E 5 above shows the frequency of occurrence of import/export between France and GB at a particular level at the time of daily demand peak. The pattern of import/export to France in 2006 and 2007 were very similar, but in 2008 we saw more frequent and higher levels of imports into GB. The shift to greater imports more frequently at the time of daily demand peak is consistent with GB-France price differentials, as illustrated in Figure E 6, where stronger GB to France price differentials also prevailed over summer 2008 peaks in line with the higher levels of import to GB.

Figure E 6 – GB-France Peak Price Differentials and Flows



33. There have been recent changes to the way system operator to system operator services across the GB to France interconnector are priced. This service, called Constraint Management and Balancing services (CM&B), now have 6 prices per day instead of just one price per day went live in March 09¹. The changes in the constraint management and balancing service (CM&B) are not an issue in respect of system security, and were introduced to improve cost reflectivity of pricing of services between ourselves and RTE. We still have relatively little operational experience of how the service will be used with the new pricing regime, so we continue to monitor the impact of the additional flexibility.
34. It is envisaged that further regime changes will occur coincident to the introduction of a new Capacity Management System (CMS) in Summer 09. The CMS is being introduced to improve how capacity is

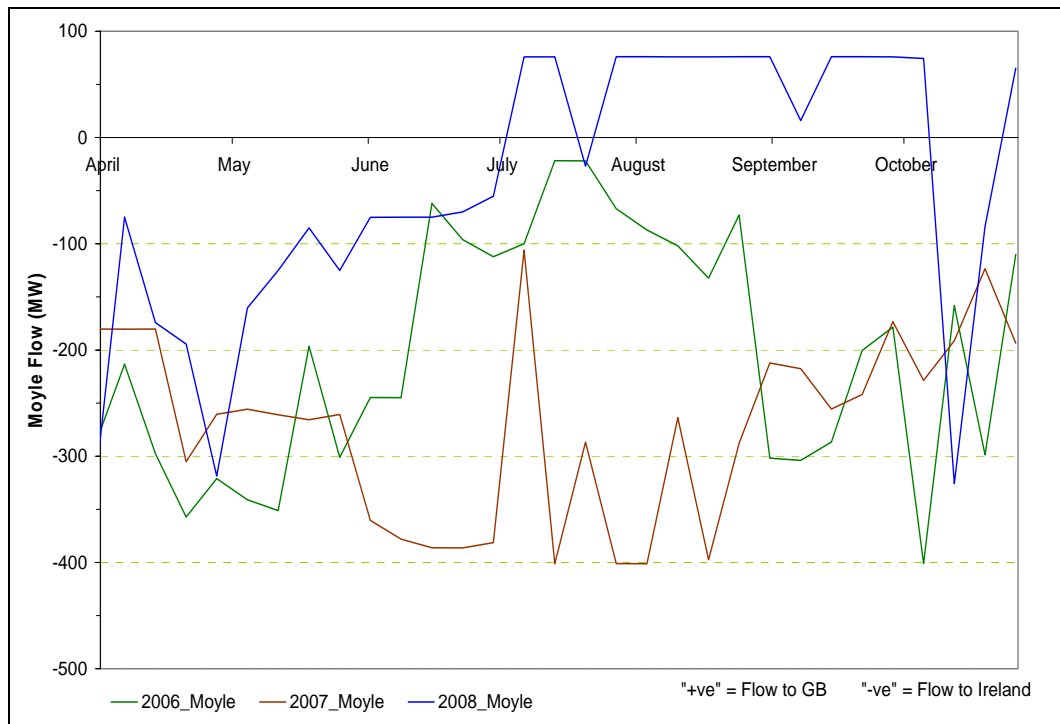
¹ See the article on changes at http://www.nationalgrid.com/NR/rdonlyres/ABA52106-0F74-402F-AF40-A88BBB9DB6A7/32187/Forum_Update_Newsletter_Feb2009.pdf

managed on the GB to France interconnector. These changes will have an impact on the way we manage the system and consequently there may be a greater requirement to take more frequent actions on specifically located generation².

Interconnector Exports to Northern Ireland

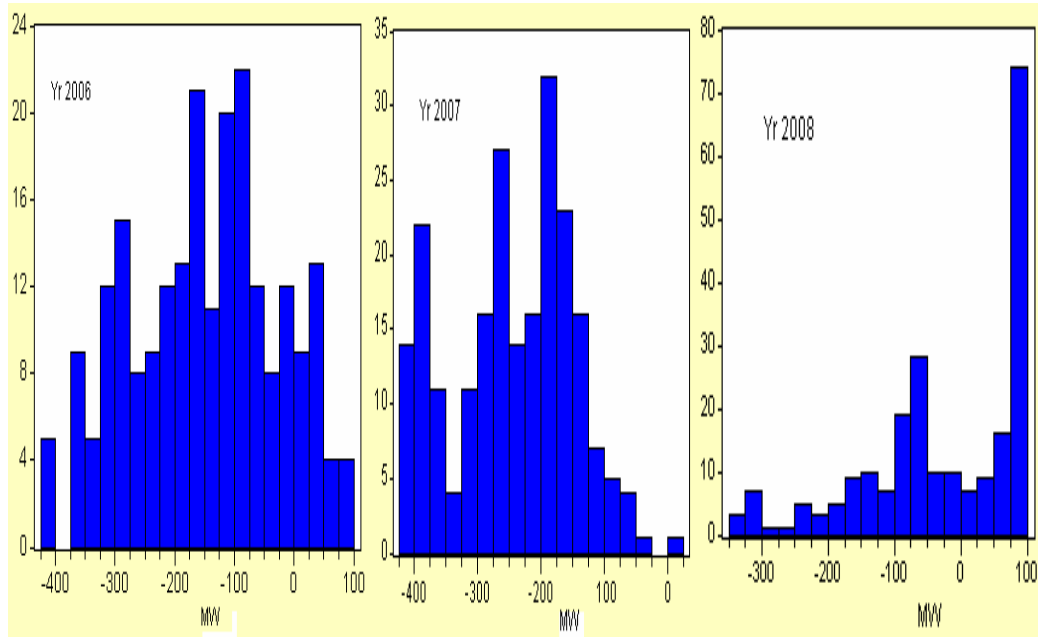
- 35. The interconnector between GB and Northern Ireland (NI) can physically export up to 500 MW to NI and import up to 250 MW to GB, though Transmission Entry Capacity (TEC) contractually limits the flow to GB to 80 MW.
- 36. Historically the pattern of summer flows between GB and Northern Ireland (NI) was mainly as an exporter to NI of around 100-400 MW. Last year though the export to NI was much reduced and we imported a lot more frequently at times of system peaks during the summer. Figure E 7 and Figure E 8 show we have historically been exporting over demand peaks, but this pattern changed in 2008 with higher levels of import to GB occurring more frequently than recent prior years. The average export over the summer at weekly peak in 2008 decreased by nearly 0.2GW compared to the two summers before and became 50MW export. The change in pattern last year was mainly driven by relative market power prices making it attractive to import power into the GB market from NI.

Figure E 7 – Moyle flows at time of TSD Weekly Peak Demand



² See Page 8 (Question 5) of our Final System Operator Incentives document for more information at <http://www.nationalgrid.com/NR/rdonlyres/75839C1D-51EE-4A36-B35E-74EAC5D3AF9D/32311/NGETSystemOperatorIncentivesFinalProposalReport.pdf>

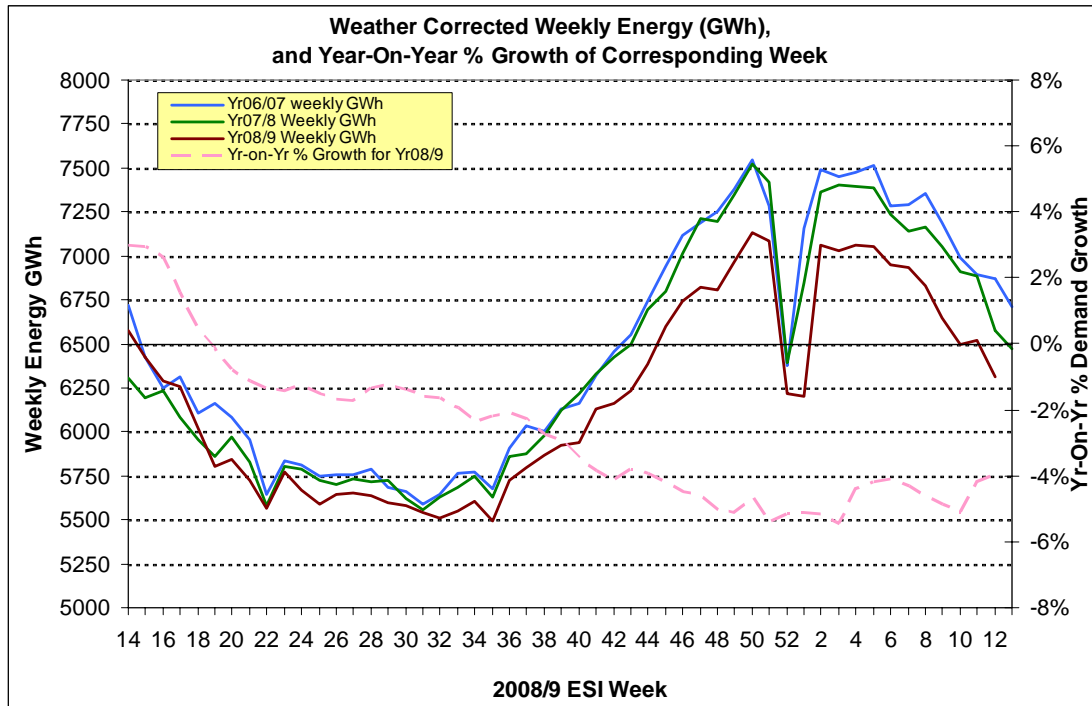
Figure E 8 – Frequency of Moyle Import/Export at time of Daily Demand Peak



Summer Demand Forecast 2009

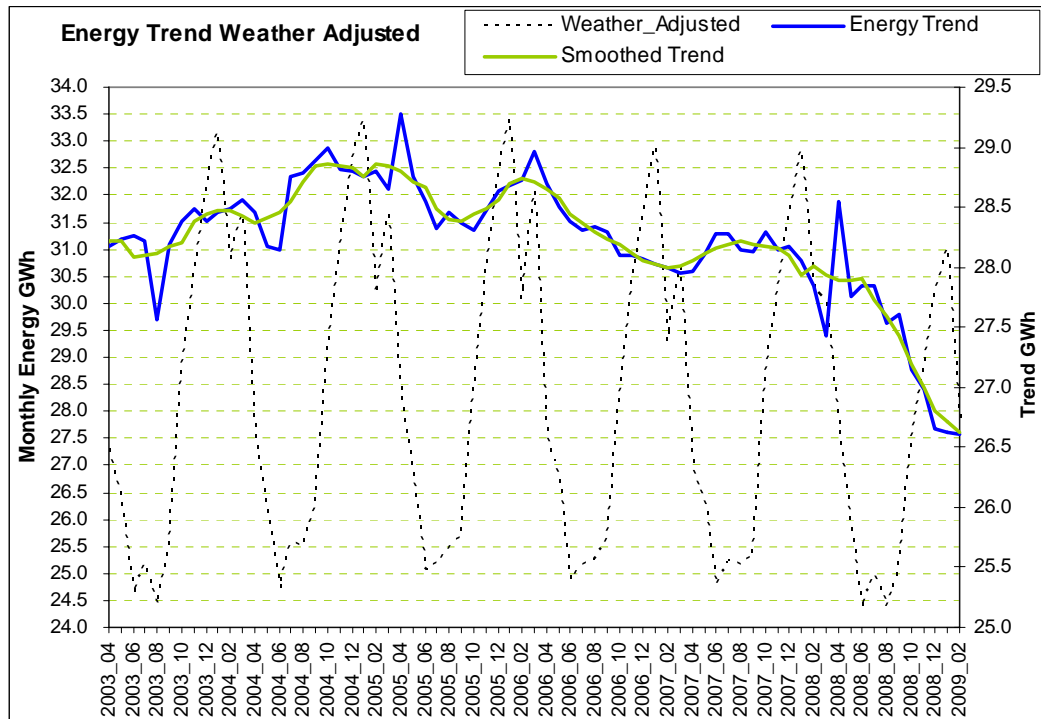
37. From late summer of 2008 we have observed a sharp down turn in electricity demand peak and energy consumption compared to the previous year. The trend is shown in Figure E 9 which depicts the weather corrected weekly energy consumption of the last 3 years. The average demand reduction was around 2 GW for the period from October 2008 to February 2009 compared to the year before with weather corrected week on week reductions in energy terms peaking at nearly 6%. The reduced demand was consistent with the negative growth of the British economy recorded in the last two quarters of 2008 which continues to be forecast by many commentators to continue through 2009. The rate of demand reduction shown in the dotted line below has slowed as the base levels in prior year referred to in the year on year growth calculation start to be reflected.

Figure E 9 – Weather Corrected Weekly Energy, and Year-On-Year % Growth of Corresponding Week



38. Furthermore, the seasonally adjusted energy demand curves shown in Figure E 10 indicate that, even before the recession, a reduction in electricity demand started to set in from 2005 due, we believe, to price responses from consumers, energy efficiency measures and growth in embedded generation. However, there was a much sharper fall in the last quarter of year 2008 as the recession took hold. Figure E 10 shows the monthly total weather corrected electricity use and is used by us for illustrating medium term trends. Given the number of years where electricity volumes taken from the transmission system have declined, we now more firmly expect this trend driven by energy efficiency, changes in usage patterns and response to prices to be likely to prevail as a trend in the medium term outlook.

Figure E 10 – Seasonal and Weather corrected Monthly Electricity Energy Consumption

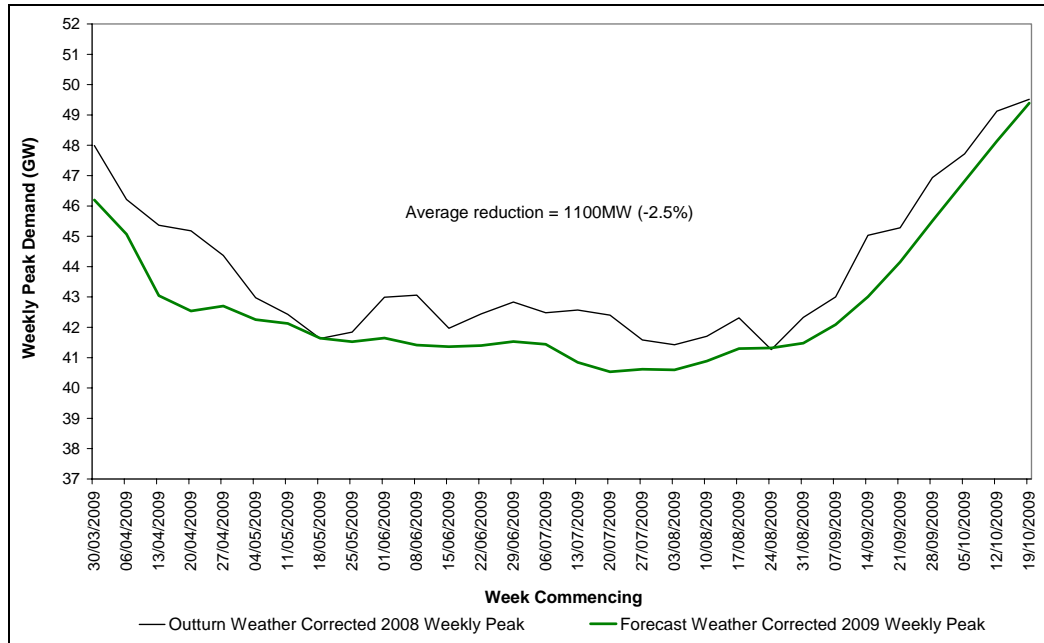


39. The economic forecasts from several different institutions suggest that the average GDP growth rate³ in 2009 will continue to be negative. For the summer 2009 demand forecast there is a higher than normal degree of uncertainty. We have assumed that the recent demand drop already reflected will continue due to the economic slow down, but there is a possibility of further reductions over the summer. Figure E 11 shows the weather corrected weekly peak of summer 2008 at weekly average weather and the forecast of summer 2009 under the same average weather conditions. The forecast will continue to be updated as part of our normal process and will be published on the www.bmreports.com web site⁴.

³ <http://www.hm-treasury.gov.uk/d/200901forecomp.pdf>

⁴ <http://www.bmreports.com/bsp/BMRSSystemData.php?pT=WEEKFC>

Fig E 11 – Summer 2009 Weekly Peak Forecast in comparison to Summer 2008



Demand Response to Weather Variation

40. The key drivers in our demand forecasting models are weather driven variables such as temperature, illumination and wind speed. Among these weather parameters, temperature has the most significant effect on demand. Table E 1 gives an indicative daily peak demand response to different weather components. The response rates depend on week of the year and also the time the peak occurs.

Table E 1 – Demand Response to Different Weather Components

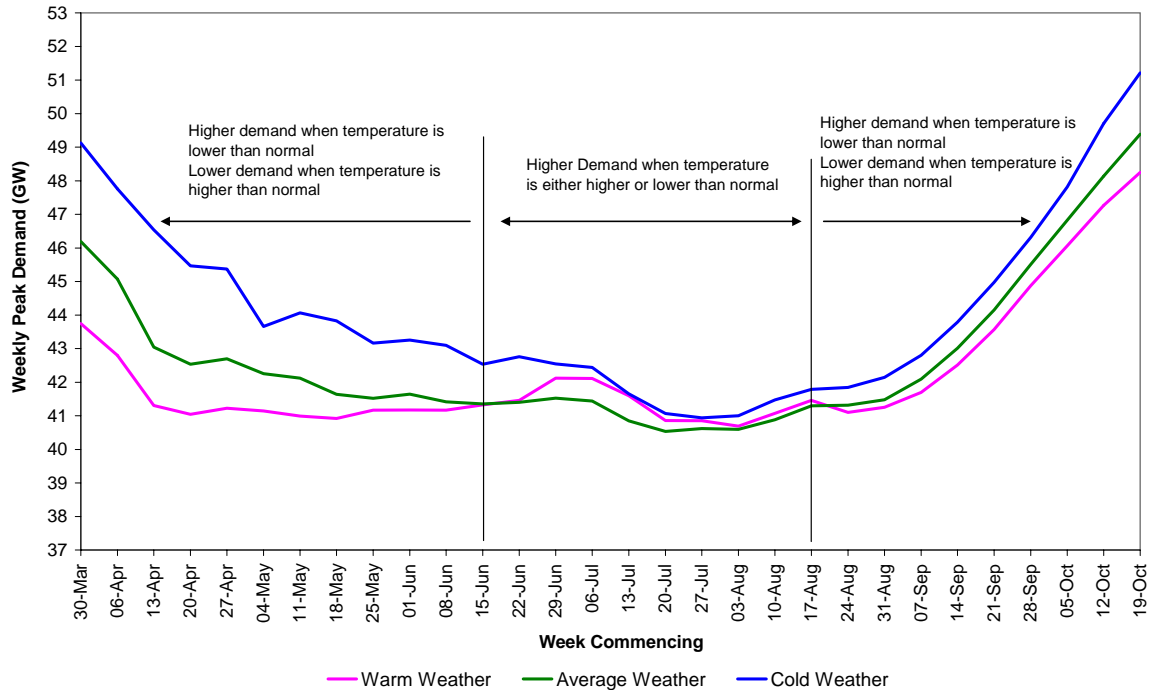
	Weather Change	Demand Change
Temperature	1 Degree increase	~ 200 – 400 MW decrease
Wind Speed	1 knot increase	~ 20 – 40 MW decrease
Effective Illumination ⁵	1 unit increase	~ 5 – 15 MW decrease

41. Demand response to weather conditions varies over different years as demand characteristics change. Figure E12 depicts the relationship between summer demand and weather, at different times of the summer, based on historic demand and weather data.

⁵ Effective Illumination is a log function of radiation that has a near linear relationship to the National Grid Demand. Its values range from 0 (dark) to about 200 units at midday in summer.

- Demand is generally higher when the temperatures are abnormally cold. This is the case between April and mid-June, and also in the late summer period from September.
- In mid-June to mid-August, the temperature is often close to the comfort temperature of 16-17 degrees. Either a fall or increase in temperature will cause demand to increase.

Figure E 12 – Electricity Demand under average, warm and cold conditions



42. In addition to assuming the underlying demand reduction, we now assume the Moyle and the GB-France interconnector are at “float” (no import or export). This compares with an average of 50MW export to Northern Ireland and import flow of 1.5 GW from France over peak periods during summer 2008. This float assumption is made to enable readers of this report to apply their own best assumptions or scenarios to electricity interconnector behaviour.

Generation Capacity

43. For the coming summer there is significantly more generation capacity installed than likely levels of demand. On this basis we expect demand can be met in full. Over the summer though electricity generation capacity goes on outages for a range of reasons and it is this post outage level of availability that shows the comfort with which demand can be met. The excess of generation availability over demand and reserve requirements is termed generation surplus and is published on www.bmreports.com. At present there is a positive surplus of generation for every week in the summer based on generation outage

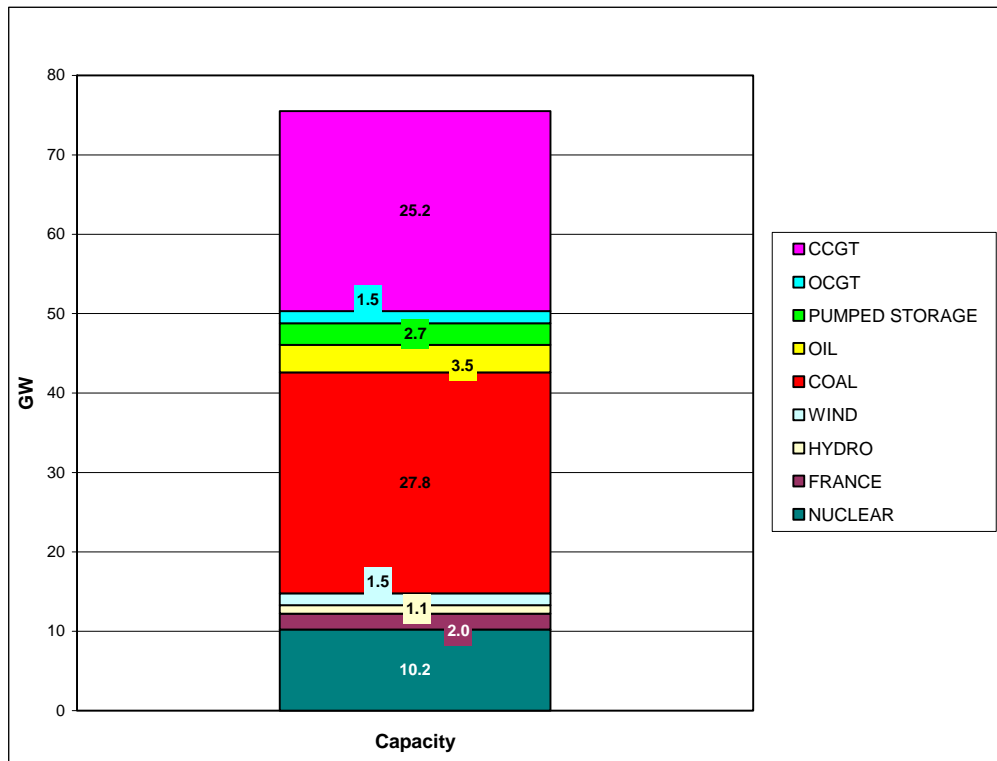
information provided to us. Therefore we expect demand should be met in full over the summer.

44. Since we completed the Winter Outlook Final Report there has been little change in the operational view of generation capacity although the planning view of installed capacity has increased. The planning view of generation capacity is based on a Transmission Entry Capacity (TEC) contracted generation capacity of 83.5 GW. This includes the 2 GW GB-France Interconnector. We highlight here the recent key changes to the planning view and also difference between it and our operational view of 75.5 GW.
45. Oldbury nuclear power station, which has a capacity of 0.4GW, has been given a life extension. It is now included in the above figures.
46. The reduced nuclear output at Hinkley Point and Hunterston, announced by British Energy in 2007, continues and represents a reduction of 0.9 GW of capacity, not reflected in the 83.5 GW SYS figure. There are no other significant known reductions in generation capacity for this summer, though the availability of opted-out LCPD generation remains uncertain but we expect it will react to market signals.
47. Several large CCGT units are expected to commission during 2009 with Langage (0.9 GW), Marchwood (0.9 GW), Immingham stage 2 (0.5 GW) and Staythorpe (1.8 GW) currently expected to start commissioning in due course. All these stations have contracted for TEC for 2009/10, but have been discounted in our calculation of available operational plant total for summer 2009 as we have taken a summer opening position as our analysis starting point. These stations represent considerable upside scope for extra availability in due course.
48. Wind continues to increase its share of the GB generation market, with a total of 1.49 GW of fully operational capacity visible to National Grid by the start of summer 2009. A further 200 MW is expected to come on line during the course of the summer with the completion of the remainder of the 322 MW wind farm at Whitelee, a small increase in the capacity at Millenium and two other small new wind farms that are due to come into operation. Our experience of wind generation is that over the summer it tends to generate on average around 20% of its maximum output, but clearly from a security of supply planning perspective this average output figure is not a valid operational assumption as wind generation output can fall to 0% or increase to near full output for periods of time. Increasing the transparency of the amount of wind generation in published generation surplus data is something we are currently investigating and we intend to bring forward options to achieve this during the summer. The published surpluses include wind farm availability based on submissions received or Operational Rated Capacity for non-submitting wind farms.

49. The TEC capacity available for summer 2009 of 83.5 GW as quoted in the SYS is a useful, broad indicator of the amount of generating plant on the system. However, new stations normally apply for TEC in advance and the 83.5 GW includes the new CCGTs mentioned above plus Severn Power and West Burton B and also some wind farms that are still under construction. It is assumed that none of this plant will be available for commercial operations this summer. This leaves 77 GW of capacity. Further reductions are made by deriving an operational view of generation capacity based on normal output being less than TEC. Hinkley Point and Hunterston provide an example of this TEC to ORC (Operational Realisable Capacity) reconciliation as described above in terms of their long term restrictions⁶.
50. This results in our current operational view of 75.5 GW of generation capacity that is anticipated to be available for the start of summer 2009. A broad breakdown of this capacity is shown in Figure E 13. We expect around 200MW of wind generation capacity to progressively become available during the course of the summer with reasonable confidence and potentially the new CCGTs when commissioned.
51. At an operational level, generators provide us with more detailed information about expected availability week by week after planned outages have been allowed for. This data is used for the calculation of the forecast surpluses and is published in regular updates on www.bmreports.com.

⁶ See the presentation here on BE's website for background http://www.british-energy.com/documents/Boiler_Seminar_FINAL.pdf

Figure E 13 – Generation Capacity – Summer 2009

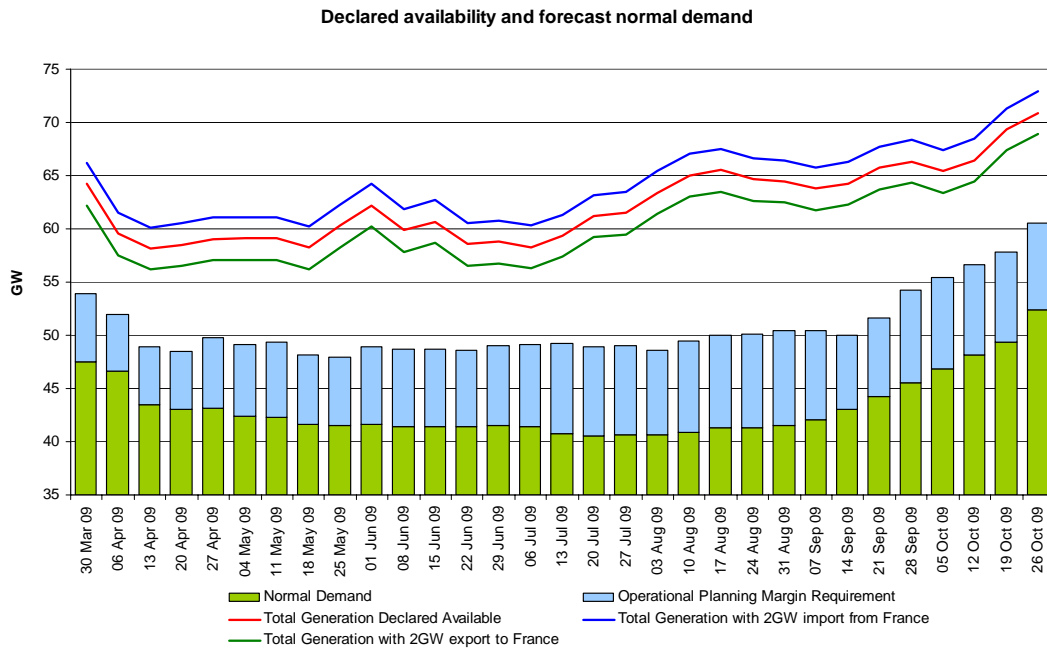


Generation Availability

52. Figure E 14 shows the normal demand levels and the generator availability declared to National Grid by Generators under Grid Code Operating Code 2 (OC2), both including and excluding 2 GW of import or export from the GB-France Interconnector⁷. As the interconnector between NI and GB is relatively small and given our base assumption of float this summer, no adjustments have been made for imports of electricity from NI (these increase available generation in a sense) and no addition has been made to the demand forecast for exports (these increase GB demand).

⁷ The French Interconnector comprises two pairs of 500MW circuits and has annual availability around 95-97%. Full availability is assumed at peak times although if an unplanned outage were to occur then availability could be reduced in increments of 500MW.

Figure E 14 – Declared Generation Availability



53. Figure E 14 illustrates a summer in which average weather conditions are experienced each week. It shows weekly expected generation availability as presently declared by generators under the Grid Code. This reflects planned unavailability as currently notified by generators outage plans, but does not include an allowance for unplanned generator unavailability.
54. It is necessary to hold varying levels of reserve such that within-day we have adequate reserve to cover for short-term generator breakdown, demand forecast errors and other specific issues such as the effects of transmission system constraints. This amounts to a requirement to discount up to 10 GW at the planning stage from the generation declared technically available. The adjustments to declared availability are shown in Figure E 13 termed OPMR (Operational Planning Margin Requirement). We publish more detailed breakdowns and explanation of our OPMR categories on our website⁸.
55. The OPMR is normally higher in the summer than winter to take account of generation plant constrained by transmission outages, particularly on the Scotland to England transmission circuits.
56. For this summer, the OPMR requirement is increased further to allow for the uncertainty in the new CCGT plants that are due to be undergoing commissioning, but declared technically available. This adjustment to the OPMR reserve requirement is stopped in respect of these commissioning plants once they have proved to be operating

⁸ See <http://www.nationalgrid.com/uk/Electricity/Data/reserve/> linking through particularly to “BMRS surplus” related data.

reliably as well as clearly also being technically available moving forward. If we did not make this adjustment for commissioning plant we would potentially be over stating the actual surplus because whilst a new plant may declare technical availability to us, this reflects ability to undertake commissioning testing and running rather than participation in the energy balancing market.

57. As can be seen in Figure E 14, with full exports from France the excess generation over average weekly peak demand would be in the range of 18-27 GW. However, this does not reflect the fact that actual power station availability tends to be considerably less than that declared 2-3 months ahead, and even in an average summer there will be times when demand is 1-1.5 GW above normal when temperatures are either above or below average, which may also be coincident with larger than average levels of shorter term generation losses.
58. We have previously highlighted that a potential impact of the LCPD (Large Combustion Plant Directive) could be that some opted out coal fired generation plant may choose to go “summer cold”. “Summer cold” refers to long notices being required by operators to start a generation unit, particularly aligned with the summer period. We do not expect this to be a key issue for meeting national energy demand as any plant would be going summer cold in response to market signals, providing that if the generation was required at some point that any operators would be able to respond in time to market signals.
59. The planned summer outages for the two largest fuel types of generation are shown in Figure E 15. This can be compared to the outages that were notified for last summer at the beginning of March 2008 shown in Figure E 16. One of the main differences is that the outage plans for gas plant seem to be biased towards the early summer, with coal station outages relatively lower in the early summer period. Also at the end of summer the planned outages as currently notified to us in 2009 are lower than in 2008, due to lower levels of planned gas outages at the end of the summer period. It is also key to note that both charts represent snapshots of outage plans for an identical group of generators in both years and that the plans are or were in place in March in the respective years 2008 and 2009. CCGT outages on average are reduced by 16% (456 MWs) on a 2009 compared with 2008 basis, with coal unavailability down by an average of 8% (533 MW). There is insufficient diversity of ownership in other generation fuel types to enable the analysis to be shown for them.

Figure E 15 – Planned outages by fuel type for 2009

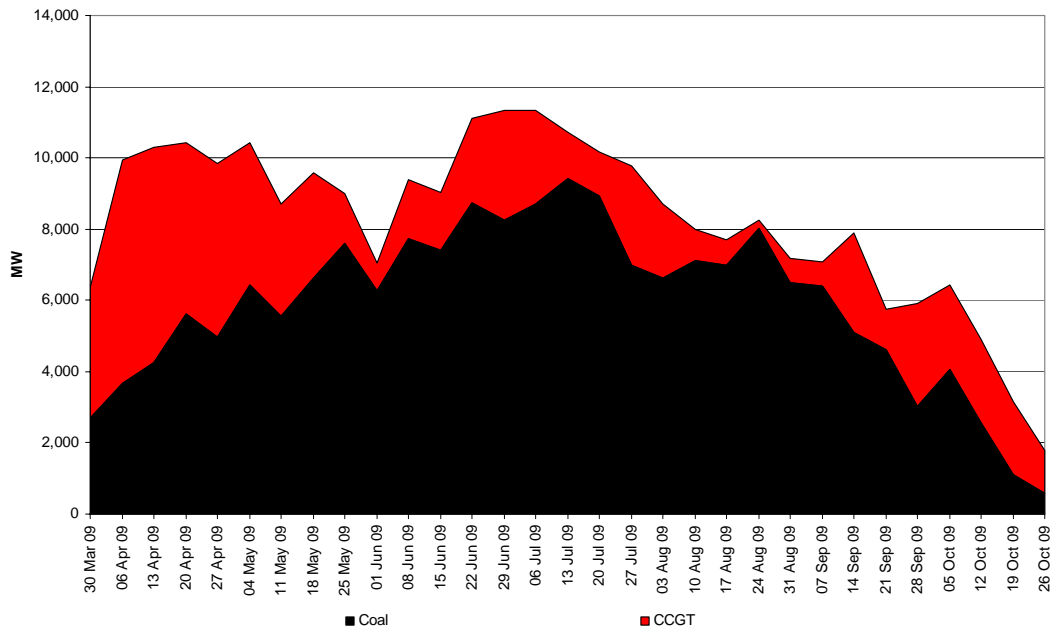
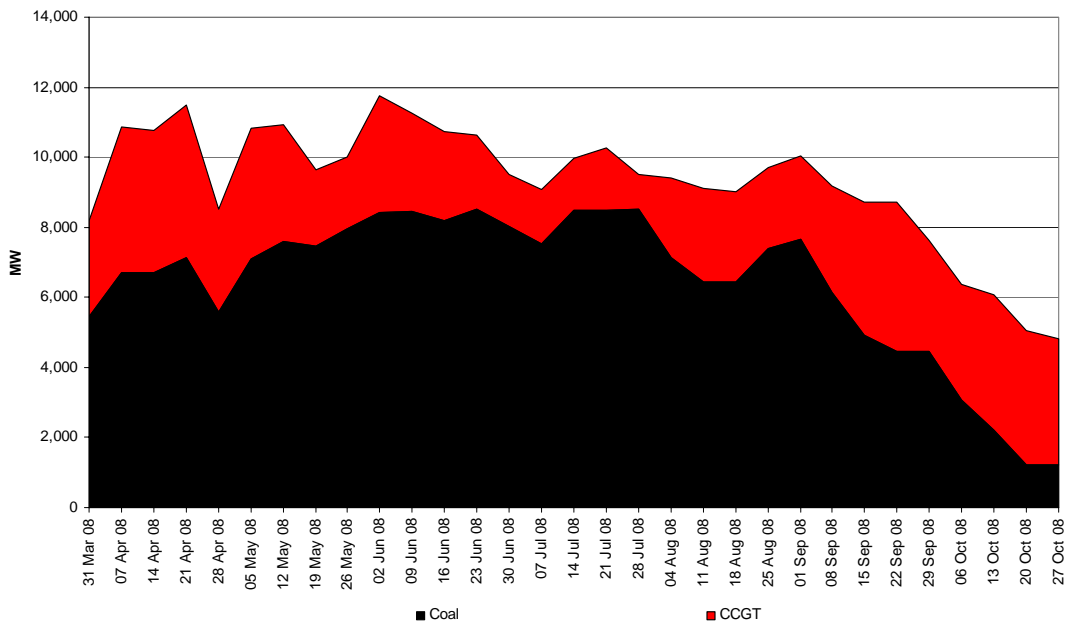


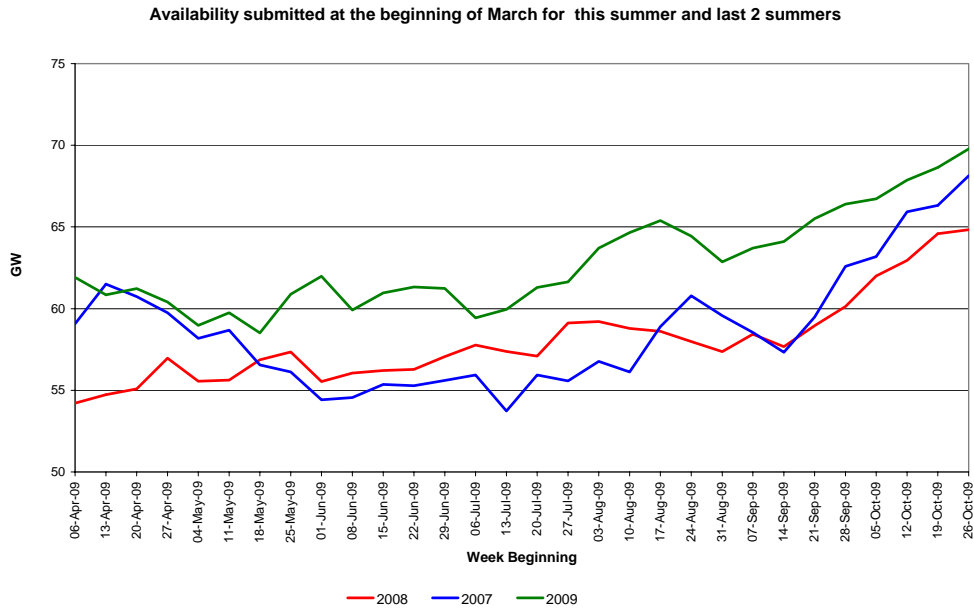
Figure E 16 – Planned outages by fuel type for 2008



60. The current levels of notified availability are higher than recent historic levels, as illustrated in Figure E 17. This is due to the improved nuclear availability and the new CCGT plants coming on stream. Note that in charts of availability the new CCGTs are treated as available, but that in terms of calculating surpluses (shown in E14) that they are

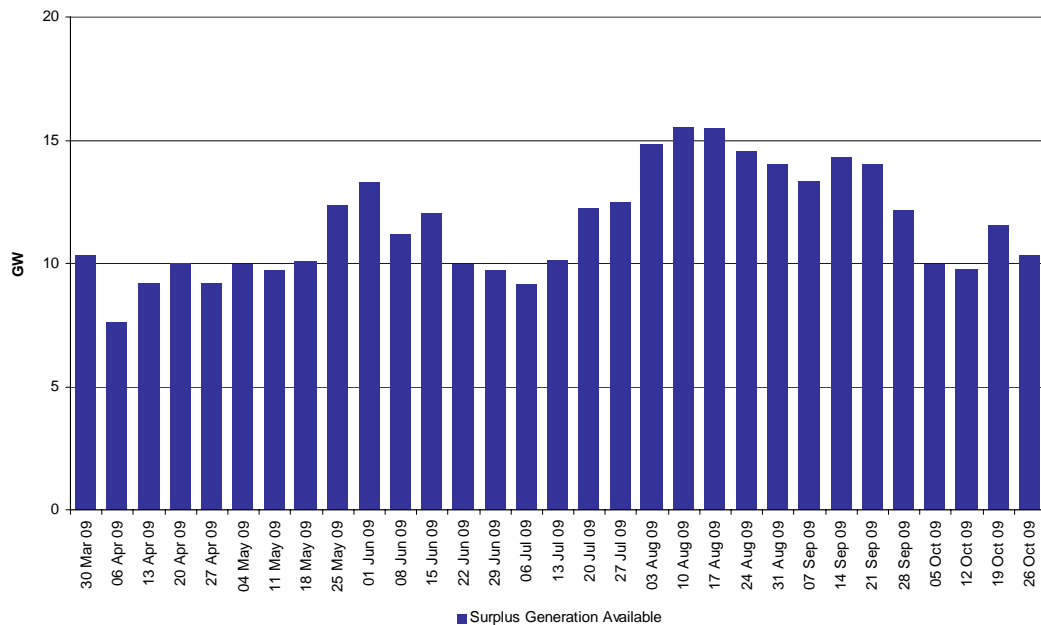
discounted until they are commercially operational through their treatment in our OPMR.

Figure E 17 – Comparison of Declared Generation Availability 2009 v 2008 and 2007



61. The current surpluses over the summer, calculated as the difference between available generation and forecast demand, are shown in E18. These surpluses will most likely be eroded closer to real time as is normal and as we discuss below. The surpluses are calculated using the base assumption that the interconnectors between GB and France and between GB and Northern Ireland are at float i.e. zero power transfer.

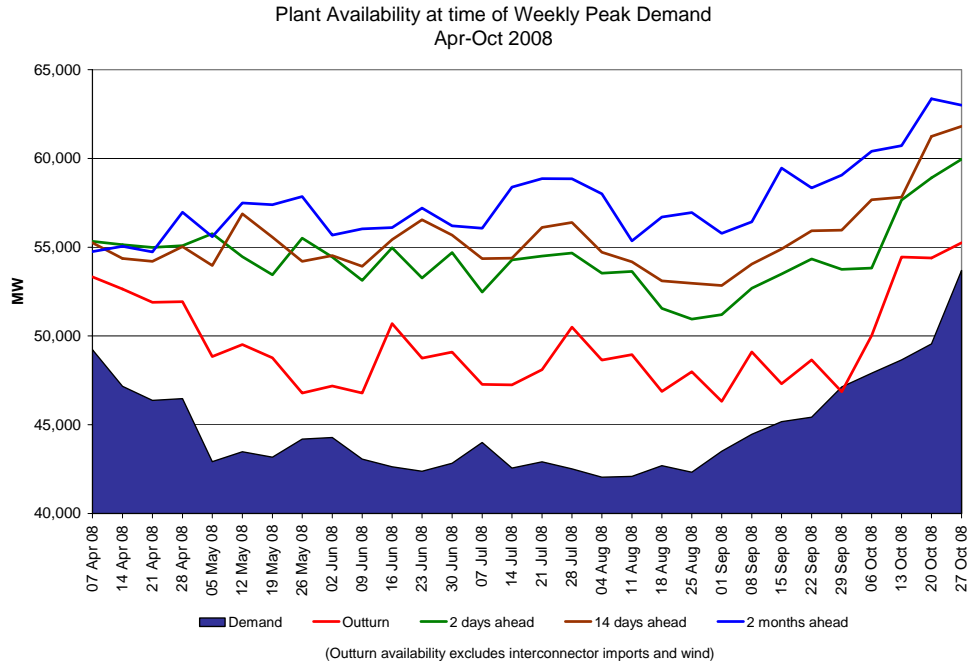
Figure E 18 – Generation Surpluses



62. Our normal operational experience at this point in the year, looking forward to the summer, is that the outturn generation availability will be significantly lower than that currently indicated by the information that has been provided at this point to National Grid by Generators. This is due to new outages being planned, short term breakdowns and plant shortfalls.
63. National Grid works with the changing generator availability as a matter of course. We expect that the market mechanisms will provide sufficient generation to meet demand and also have tools we use as normal operational practice to aid market operation such as system warnings. We also ourselves flex our transmission system outage plans to contribute to maximising generation availability where necessary.
64. There are occasions when we see an increase in the generation available nearer real time. For instance, if surpluses are very tight, more generation may make itself available through the normal functioning of market mechanisms.
65. Figure E 19 below shows the generation availability last summer at the time of the weekly peak demand as it evolved from 2 months ahead to real time. This shows that the outturn surplus historically dropped by up to 12 GW compared to the position at 2 months ahead.
66. The chart shows that within day availability was just less than demand for the peak in week beginning 29 September 2008. However, this chart presents a partial picture of power available to us as system operator as in addition there were imports through the French and Northern Ireland interconnectors and there was a small amount of

wind generation, which when combined with the available generation plant provided a real time margin of just under 2000 MW.

Figure E 19 – Changes to Generation Availability for summer 2008



System Warnings

67. System warnings may occur at any time of the year. Recent experience shows they may be issued in high summer as occurred for 6 days between April and September inclusive last summer. System warnings during the summer have most often been associated with short term generation unavailability relative to demand and limited compensatory action by the market in making replacement generation available. System warnings are a useful tool for us to highlight a potential issue to stimulate market reaction where it hasn't already taken place to make additional generation plant available or additional demand side services.

Market Information

68. In response to industry requests, National Grid and Elexon have made some improvements to electricity operational information. A summary of key parameters, including demand, generation availability and surpluses are calculated by National Grid and are published on a rolling update basis on the Elexon BM Reports website⁹.

⁹ See http://www.bmreports.com/bsp/bsp_home.htm for the new electricity market summary page that went live on 12th March 2008 with a second phase of enhancements following on 6th November 2008.

69. This information helps to facilitate efficient market operation as it informs market participants of the expected levels of demand and therefore the amount of generation they may need to contract with to meet their customers' demand. This summer will be the first summer where these recent improvements have been in place.
70. We continue to proactively review the operational information we receive and also provide to the market to ensure that we are able to facilitate efficient market operation and safe, secure and efficient and economic power system operation. We expect to bring forward some proposals over the summer for consideration of some further targeted improvements such as to better reflect the contribution of wind generation to our indicated surpluses, given wind generation's intermittency and we also intend to take forward more work with wind farm operators to enable us to receive improved operational information from them.

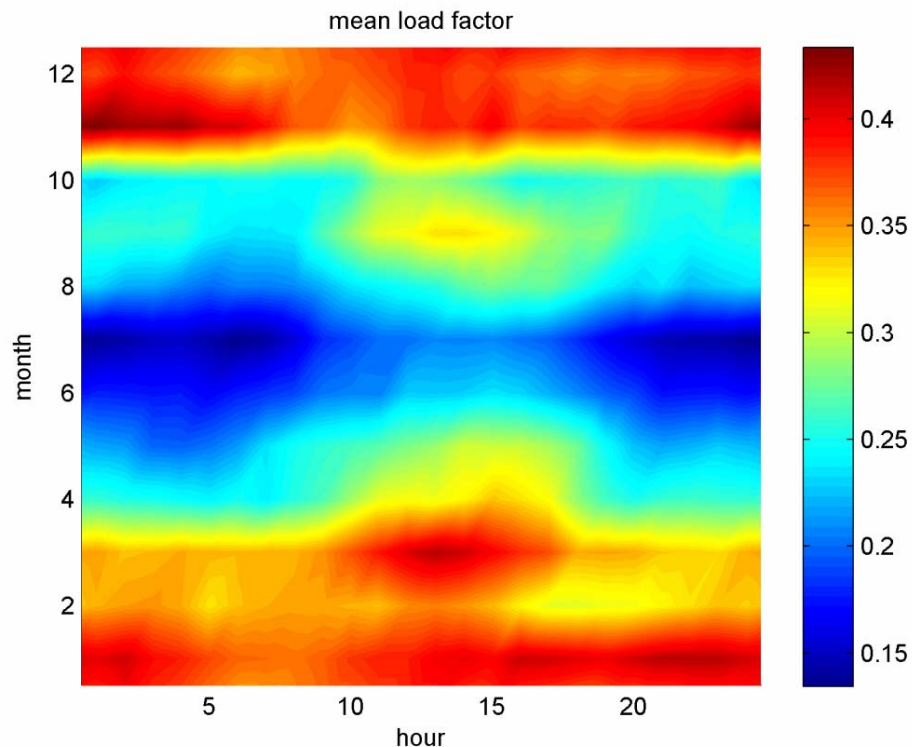
Wind

71. Wind continues to increase its share of the GB generation market, with about 1.5 GW of fully operational capacity visible to National Grid by the start of summer 2009/10. The increase from last year's summer position has been small, but wind power variability is already a key area of operational focus for us and is expected as a generation type to significantly increase in capacity going forward. Our experience of wind generation is that over the summer it tends to generate on average between 15 and 25% of its maximum output, as detailed in Figure E 20. However as we have outlined in our winter outlook report for 2008/09 and recently at our electricity operational forum¹⁰ we do not see monthly average generation load factors as directly relevant for security of supply considerations where more appropriately a "capacity credit" is required.
72. We are currently completing a National Grid project to assess in detail an operational capacity credit and have in parallel provided data for an independent research project at Edinburgh University into the appropriate "capacity credit" to calculate the appropriate percentage of credit to assign to wind generation whilst maintaining our current security of supply standards. We aim to have the results of both areas of work available to allow us to consult through our winter outlook preliminary report on a capacity credit level to apply to wind generation in the winter outlook report going forward. We also intend to take a scenario based approach to wind generation output in our published energy planning analysis.

¹⁰ http://www.nationalgrid.com/NR/rdonlyres/947BE138-A742-4E6B-930D-C2FE072CC1A2/32264/Feb2009_04_Future_System_Operation.pdf presented at our 24th February 2009 forum outlines a range of issues for the future including references to security of supply considerations with a significant amount of installed wind generation capacity and the need for associated reserve provision.

73. We provided detailed results of recent analysis of historic wind generation load factors in the Winter 2008/09 report which can be found on our website¹¹. Figure E 20 shows the generally lower load factors seen in summer from wind and also the fact that wind generation tends to have a lower load factor over night.
74. Since we published our last outlook report for winter 2008/09 we have now started publishing an initial and updated wind power output forecast along with corresponding actual generation seen on www.bmreports.com¹².

Figure E 20 – Historic GB wind load factors by month and time of day



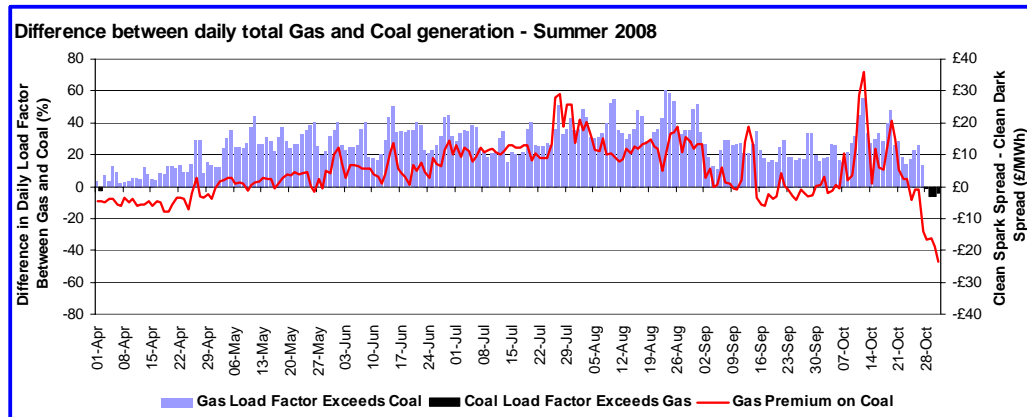
Merit Order

75. Figure E 21 shows the relationship between spark and dark spreads over summer 2008. It can be seen that throughout the summer the spark spread remained higher than the dark spread leading to a higher load factor for gas generation than coal.

¹¹ http://www.nationalgrid.com/NR/rdonlyres/1BB72E89-3B65-4DF4-9B98-0906C75C53E4/28643/Winter_Outlook_2008_final.pdf

¹² See http://www.bmreports.com/bsp/bsp_home.htm and scroll to the "wind forecast outturn" chart.

Figure E 21 – 2008 Summer Coal and Gas Load Factors and Clean Spreads.



- 76. At current market prices for summer 2009 there is very little difference between clean spark and clean dark spreads (see appendix 1). Fuel prices are very volatile and clearly this may change. Additionally, gas-fired generation is very dependent upon gas spot prices whereas coal is often traded on longer term fixed price contracts. Hence the merit order can also vary on a daily basis particularly depending upon the spot gas price.
- 77. Forward GB prices for peak and baseload power are currently higher than France over summer as a whole. However the premium over peaks is not particularly high. Generally prices are volatile and therefore we cannot make a strong assumption based on today's prices that there will be a flow towards GB. What has been shown to occur is that the flows on the French interconnector react to relative prices between European and GB prices. We provide more detail in Appendix I on fuel prices. There remains the potential for periods of high exports to France in response to higher relative France to GB prices at key times in the summer.

Transmission System Issues

- 78. Spring 2009 sees the continuation of major works to construct or rebuild major sections of the transmission system in Scotland and the North of England, to deliver additional transmission capacity to transport energy from new renewable generation (wind) in Scotland and the North of England, as part of the Transmission Investment for Renewable Generation (TIRG) works.
- 79. As part of this project, major outages are required to upgrade the capacity of the transmission circuits that cross the Cheviot boundary. This is the second year of a three year project to upgrade the transmission capacity of the circuits crossing this boundary from 2.2 GW to 3.2 GW by 2011/12.
- 80. This scale of works, at 36 weeks in a single year, is even more significant than last year and the resultant reduction in transmission

capacity is expected to lead to a significant increase in constraint volumes, cost and risk on the Cheviot boundary for the period of the works, which already started in late March 2009.

81. Uncertainties remain around the outages, due to the possibility of change to the programme or acceleration or delays to works by the Transmission Owners (National Grid, SPT and SHETL). However it is expected that throughout summer 2009 there will be an unbroken programme of planned outages on one or other of the two boundary circuits themselves. An outage on one of the two double circuits reduces the boundary transmission capacity from an average of 2.2 GW to between 0.6 GW and 1.6GW, depending on the precise nature of the outage.
82. The network outages to undertake the work will reduce the available transmission system capacity on the boundary between Scotland and England, and across several internal Scottish boundaries, and require National Grid to constrain generation output down to keep the system operating safely and securely.
83. To manage this uncertainty, we will use a combination of (i) contracts to limit the output of certain power stations; (ii) arming of intertrips to automatically disconnect generation in the event of a transmission fault, (iii) actions on the day in the Balancing Mechanism, and (iv) trades or pre-gate balancing transactions (PGBTs) to resolve these constraints efficiently and effectively.
84. As a consequence of needing to manage power flows across the boundary circuits by constraining off generation, up to 2 GW of generation within Scotland may be unavailable to National Grid this summer.
85. The reinforcement of the transmission network in Scotland and the North of England form part of a substantial development of the networks to accommodate new generation and to replace assets to ensure the continued reliable performance of the GB transmission system. Details of planned reinforcements in England and Wales are shown in National Grid's Seven Year Statement <http://www.nationalgrid.com/uk/Electricity/SYS/>

Chapter 2: Gas

Introduction

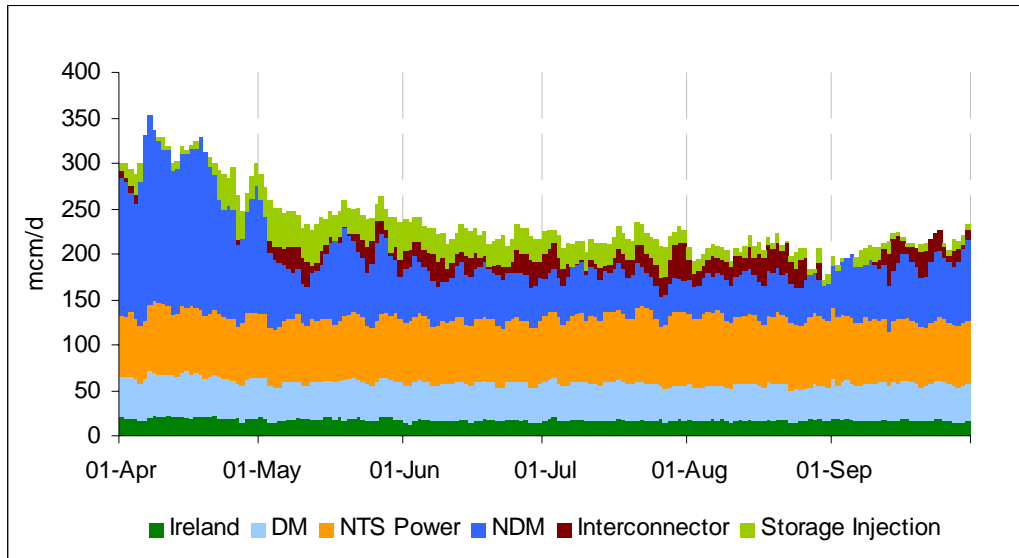
86. This Chapter focuses on the gas supply-demand outlook for the forthcoming summer. With demand levels at typically half those experienced in the winter, we are confident that demand will be met in all but exceptional circumstances. There is however considerable uncertainty on how supply will be utilised to meet demand. This is further compounded by annual maintenance to upstream supply infrastructure, the need to refill storage and the interaction of global and Continental markets on LNG and Interconnector (IUK) flows respectively
87. In this Chapter we examine issues associated with gas demand and gas supply. These include a high level assessment of the economics of choice of fuel for power generation and the prospects for gas imports / exports. We also provide an assessment on how summer performance may be affected by operational maintenance and new infrastructure. Changes to the regulatory regime are detailed in Chapter 3.

Historical Summer Gas Demand

88. As in the winter, gas demand in the summer can be assessed in terms of weather sensitive demands (Non Daily Metered – NDM) and non weather sensitive demands. The latter includes Daily Metered (DM), exports to Ireland¹³ and the Continent, power station demand and storage injection.
89. Due to the possibility of lower temperatures, weather has the biggest impact on summer gas demand during April, May and late September. April and September 2008 were the coldest since 2001, whilst May 2008 was the warmest on record. The impact of climate change has resulted in a general trend of warmer springs and earlier summers.
90. None of the summer demands reported in this paper are weather corrected as the need to correct for unseasonable weather in the summer is far less than for the winter.
91. Figure G1 shows the gas demand experienced in summer 2008.

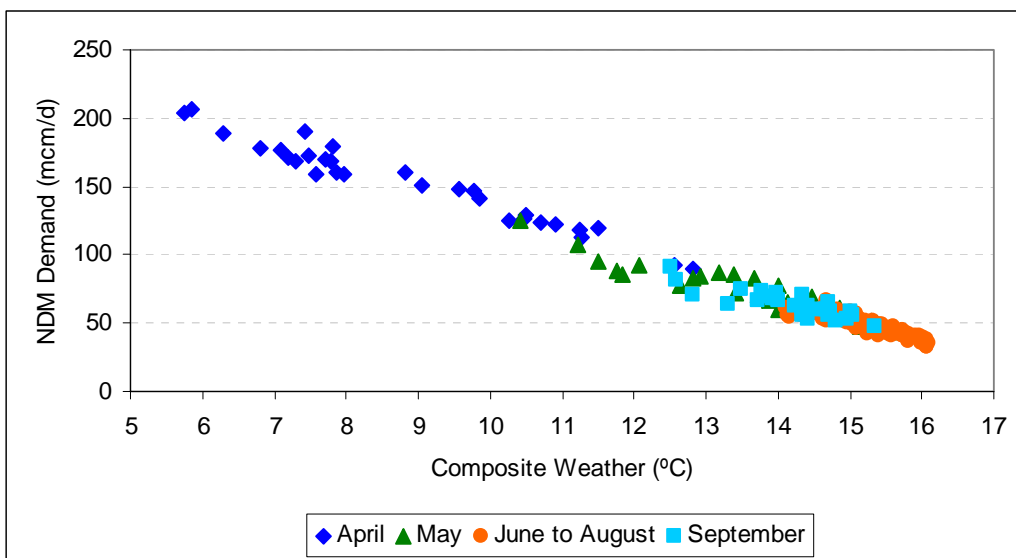
¹³ Some smaller DM loads are partially weather sensitive as are exports to Ireland

Figure G1 – Summer Gas Demand 2008



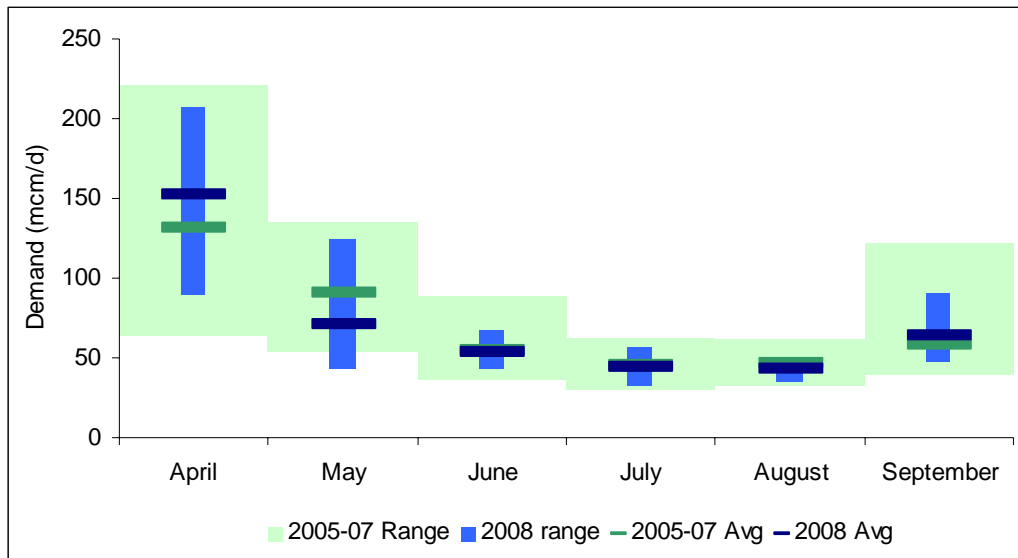
- 92. The chart highlights relatively stable flows in terms of exports to Ireland, DM and NTS power generation. The NDM profile highlights the sensitivity to weather whilst storage injection and IUK exports are primarily determined by refill requirements and price differentials respectively.
- 93. Figure G2 shows the relationship between weather expressed in terms of a Composite Weather Variable (CWV) and NDM demand for summer 2008.

Figure G2 – NDM 2008 Summer Demand



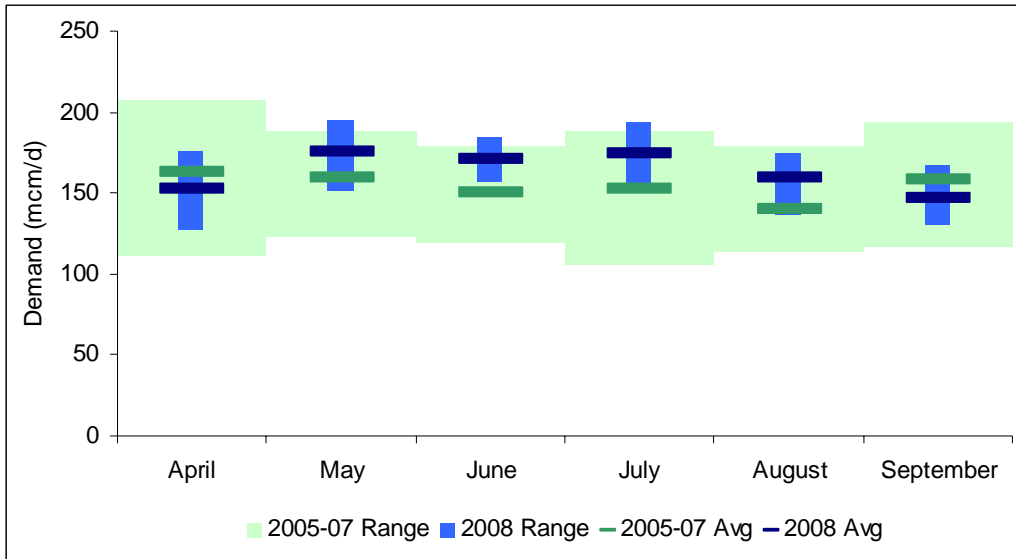
94. The NDM demand for summer 2008 is typical of most summers whereby gas demand can be considered in 3 separate periods; namely:
- i) the late spring /early summer when NDM gas demand is falling
 - ii) the mid summer period from June to August when NDM demand is essentially flat
 - iii) the September increase in NDM gas demand as temperatures start to fall
95. Figure G3 shows NDM summer demands between 2005 and 2007 in terms of minimum, average and maximum demands for each calendar month. Also shown explicitly is the same demand data for 2008.

Figure G3 – NDM Summer Demands (2005 – 2008)



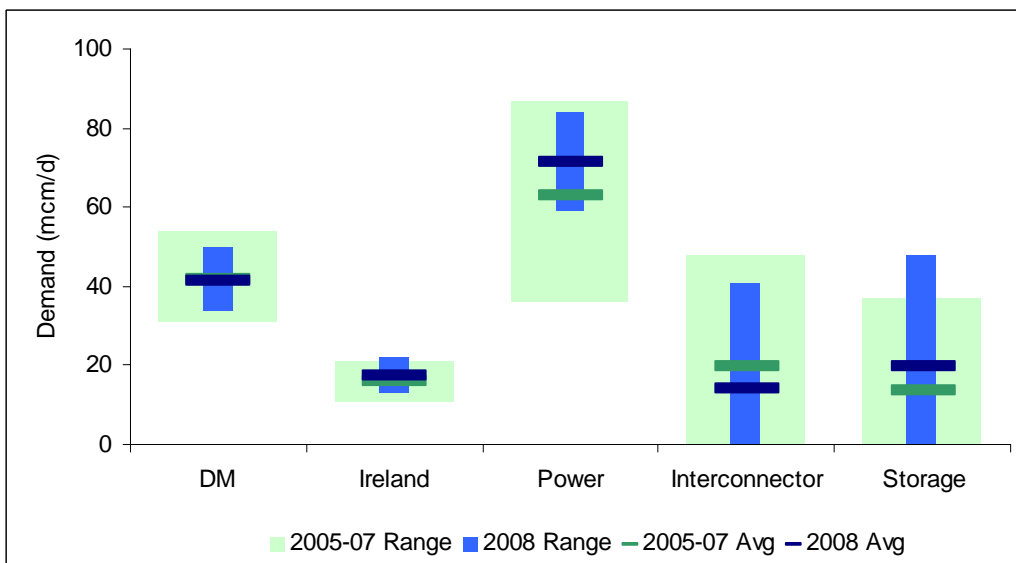
96. The chart highlights how much NDM demand variation can occur in the shoulder months (April, May & September) compared to the mid summer period. To put this into context, for the months of June, July and August the average NDM demand has been about 50 mcm/d, during this period the NDM demand has been within a +/- 15 mcm/d range for over 90% of all days.
97. With the exception of some lower demands in May 2008 all summer demands in 2008 fall within the previous 3 summers.
98. In a similar manner, Figure G4 shows all other demands, namely the non weather sensitive demands of DM, exports, storage injection and power generation between 2005 and 2007 in terms of minimum, average and maximum demands for each calendar month. Also shown explicitly is the same demand data for 2008.

Figure G4 – DM, Export, Storage Injection & Power Generation Summer Demands (2005 – 2008)



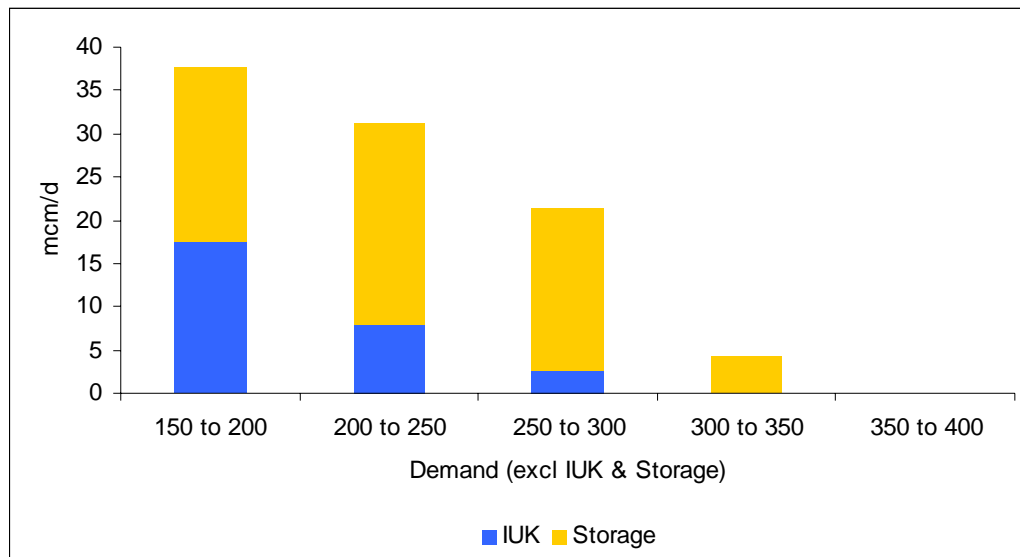
- 99. Whilst the chart highlights the lack of weather sensitivity in these demands, it also clearly shows the potential range of demands from about 100 to 200 mcm/d with an average of about 150 mcm/d. The data set for 2008 shows a tighter data set of demands and higher demands for much of the mid summer period.
- 100. This range of potential demands for each of these demand components is shown in Figure G5.

Figure G5 – Range of DM, Export & Power Generation Summer Demands (2005 – 2008)



- 101. The chart highlights relatively modest variations in DM and Irish demand of just 25 and 10 mcm/d respectively. However, the variations for power generation, IUK exports and storage injection have at times been as high as 50 mcm/d. The chart also shows higher utilisation for power generation in 2008 and as a consequence a tighter range below 30 mcm/d.
- 102. Historically, the drivers behind the range for power generation have been plant maintenance and fuel costs whilst the range for IUK exports have been determined by price differentials and Continental demand for gas. This in turn has been influenced by supply contracts, demand to refill storage and access to transportation. Consequently, the range of non weather sensitive demands experienced of about 100 to 200 mcm/d could theoretically be much greater at about 80 to 230 mcm/d.
- 103. Figure G6 shows IUK exports and storage injection experienced in summer 2008 against, expressed against total demand excluding IUK exports and storage injection.

Figure G6 – IUK export and storage injection in summer 2008



- 104. The chart highlights the increase in IUK exports and storage injection at lower demands, thus playing a key role in reducing the overall variation in summer demand.
- 105. Table G1 shows the total gas demand for April to September from 2005 to 2008 for NDM and all the demand components in Figure G5.

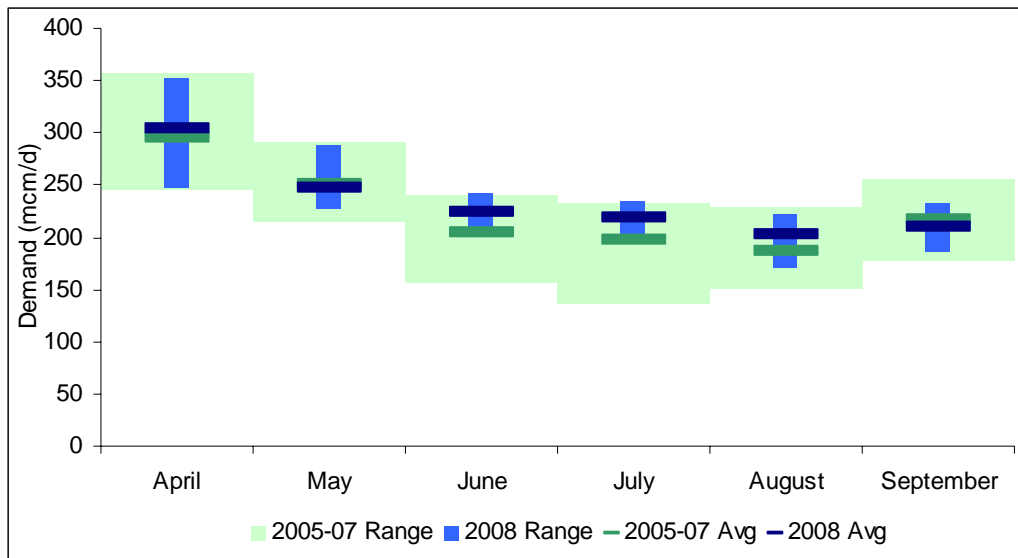
Table G1 – Summer Gas Demand (2005 – 2008)

(bcm)	NDM	DM	Ireland	Power	IUK	Storage	Total
2005	14.1	8.1	2.7	11.4	2.9	2.4	41.6
2006	12.7	7.5	3.0	10.4	4.5	1.4	39.4
2007	12.3	7.3	3.1	12.7	3.4	1.4	40.3
2008	13.0	7.5	3.2	13.1	2.5	2.6	42.0
Average	13.0	7.6	3.0	11.9	3.3	2.0	40.8
%	32%	19%	7%	29%	8%	5%	100%

106. Table G1 shows aggregated April to September demands of about 41 bcm. The general trends suggest a decline in NDM and higher use of gas for power generation.

107. For completeness of charts, Figure G7 shows for summers 2005 to 2007, on a monthly basis minimum, average and maximum demands for each calendar month for total demands; namely the combination of NDM and the non weather sensitive demands. Also shown explicitly is the same demand data for 2008.

Figure G7 – Total Summer Demands (2005 – 2008)

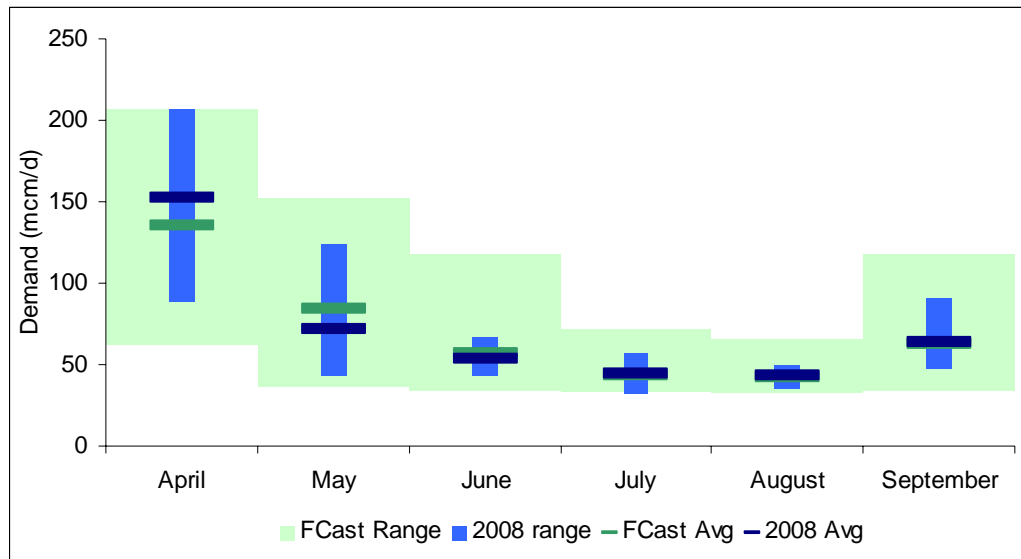


108. In terms of average demand, the chart again highlights the variation in demand for the shoulder months and the relatively stable demands for the mid summer period. Overall there is considerable variation in terms of the range of demand, even during the mid summer period with average demands of typically 200 mcm/d there has been days of demand as high as 240 mcm/d and as low as 140 mcm/d. As detailed previously these are primarily driven by IUK exports and power generation. By contrast, the demands experienced in 2008 (noticeably in mid summer) tended to be in a much tighter range with most demand days at or above 200 mcm/d.

Forecast Summer 2009 Gas Demand

109. Figure G8 shows the monthly variation in forecast daily NDM demand based on the weather experienced in the last 20 years. Also shown is the actual variations experienced last summer. If our 80 year data set were used, the upper range would be higher. These ranges reflect the 6% reduction in weather corrected NDM demand observed during the 2008/9 winter and the potential for much higher demands in mid-summer if the weather is colder.

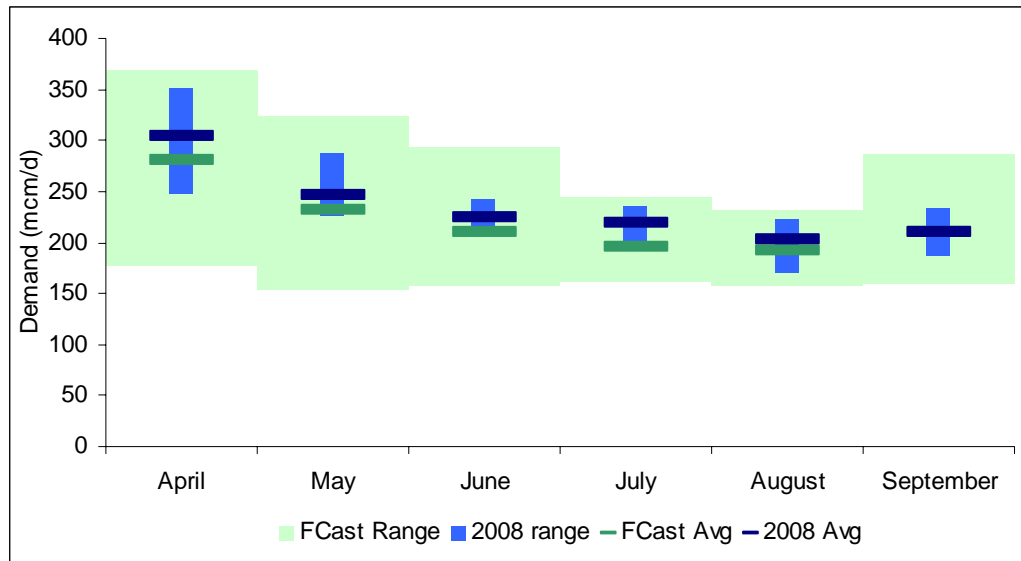
Figure G8 – NDM demand forecast for Summer 2009



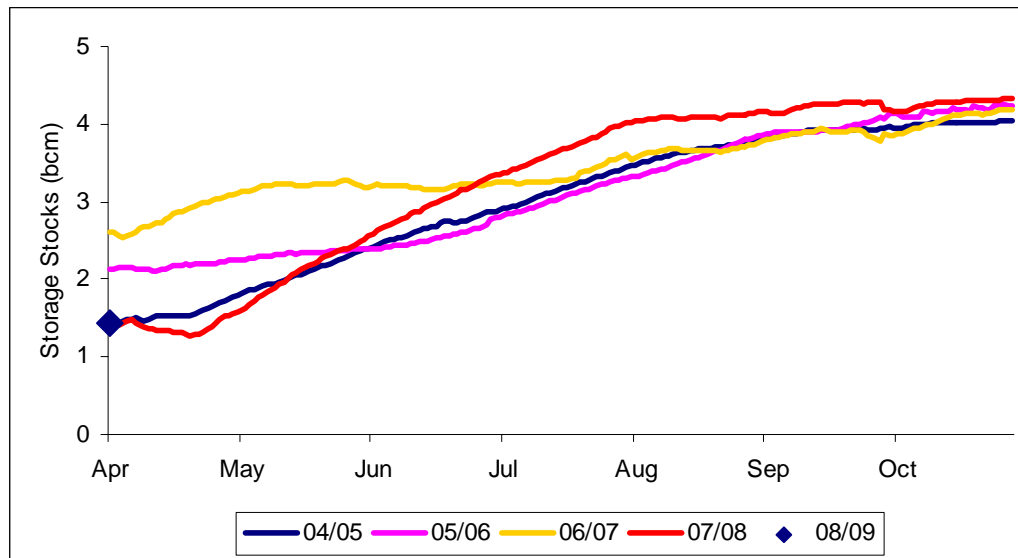
110. Forecasts demands for Irish exports this summer are not expected to change much from those experienced in the last four years. Over the winter the impact of the recession has been to reduce demand in the LDZ DM and NTS industrial sectors by 5 to 6 mcm/day.

111. Figure G9 shows our forecast for total summer demand for each month expressed as an average demand and a range. Also shown is the actual data for 2008.

Figure G9 – Total demand forecast for Summer 2009

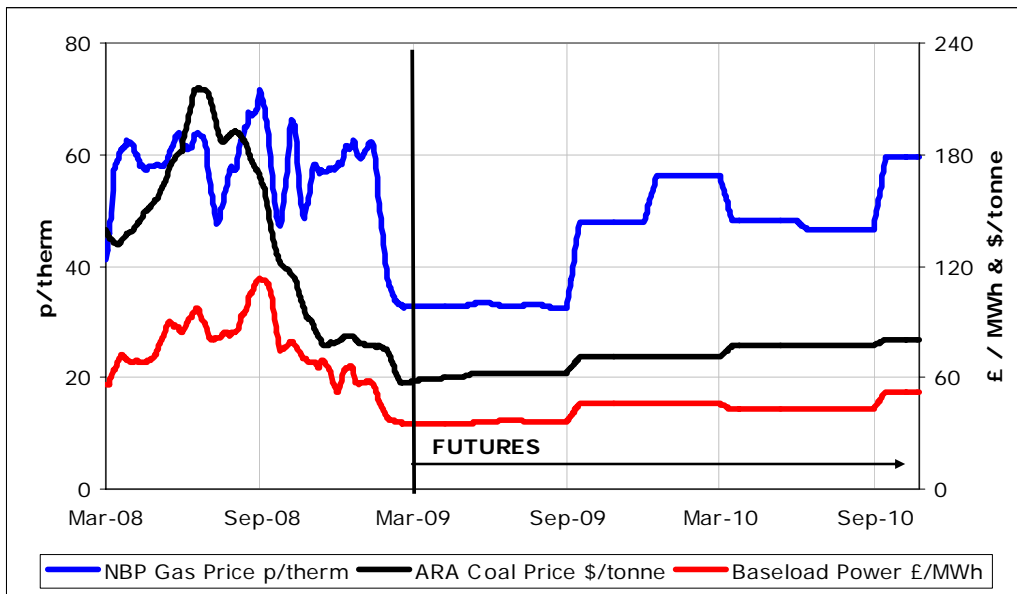


112. The total demand forecast is similar to last year though marginally lower to reflect an expectation of lower demand primarily through the effects of the recession.
113. Due to increased storage use last winter and the expected commencement of operations at Aldbrough for next winter, forecast gas demand for storage injection this summer could be marginally higher than the range experienced over the past 4 years (Figure G5). Depending on refill plans, the duration for storage injection could also be longer. In general, if NDM gas demand is higher than expected due to a colder spell of weather, with a corresponding increase in spot prices, we would expect to see less storage injection and possibly lower IUK exports.
114. Figure G10 shows the refilling of storage during the last four summers through aggregated storage stock levels. Despite variations in the need to refill by up to 1 bcm, storage stocks levels have been comparable by August. For 2009 injection, storage stocks are expected at the start of April to be comparable to the storage level in 2008. For 2009 (including Aldbrough), over 3 bcm of storage needs to be refilled. Historically average filling rates have been about 15 mcm/d with maximum storage rates above 50 mcm/d. Hence with approximately 3 bcm to be refilled, the duration is expected to be between about 100 and 200 days, well in time for next winter.

Figure G10 – Aggregated Storage Stocks 2005 - 2008

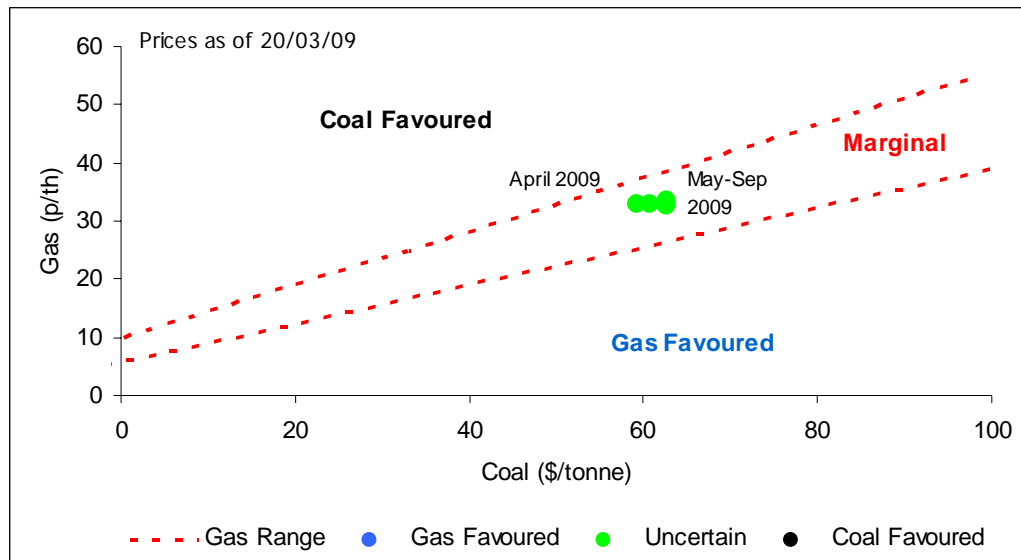
115. Forecasting gas demand for IUK exports this summer is as in previous years, difficult to determine. The price differentials between NBP and Zeebrugge (Figure G16) remain very small, currently favouring exports flows rather than imports. One factor that may promote lower exports this summer than in 2008 is the possibility of contractual obligations from suppliers coupled with lower Continental demand due to the global recession. Compared to last winter Continental storage stocks are estimated to be more than 5 bcm lower than in 2008, hence this might therefore result in higher IUK exports.
116. Assessment of the mid summer period (see Figures G1 and G5) reveal that power generation demand is the largest single demand component making up approximately one third of total gas demand.
117. The seasonality of the UK gas price has historically seen gas-fired power stations used for base load generation in the summer with coal used as the marginal source. The European Union Emissions Trading Scheme (EU ETS) reduces coal's competitive advantage when compared with gas due to higher associated carbon emissions. The Large Combustion Plant Directive (LCPD) which came into operation at the beginning of 2008 has also reduced coal demand to a certain degree as some UK plants can only generate for a limited number of hours between 2008 and 2015. Hence these plants are expected to operate more when electricity prices are higher in the winter months rather than the summer.
118. Figure G11 shows historic and forward gas, coal and power prices for coal, gas and base load power. The chart shows that fuel prices have fallen dramatically since mid-2008, principally driven by low demands due to the global economic downturn.

Figure G11 – Historic and Future Fuel Prices



119. In terms of the choice of fuel for power generation this summer, coal has also benefited from the current low carbon prices which have fallen principally due to reduced emissions driven by lower demands. In determining the dark and spark spreads for summer 2008 (see Figure E1) we have used the fuel, carbon and power prices shown in Appendix 1.
120. As discussed briefly in Chapter 1, the current forward prices of gas, coal, power and carbon suggest that there is little to choose between gas and coal in terms of the economics for power generation this summer. This is shown in Figure G12 in terms of a price plot of coal versus gas. The current and forward prices of about 33 p/therm for gas and 60 \$/tonne for coal show very little variation until next winter when the seasonal pricing for gas returns.

Figure G12 – Coal versus Gas Generation Plot

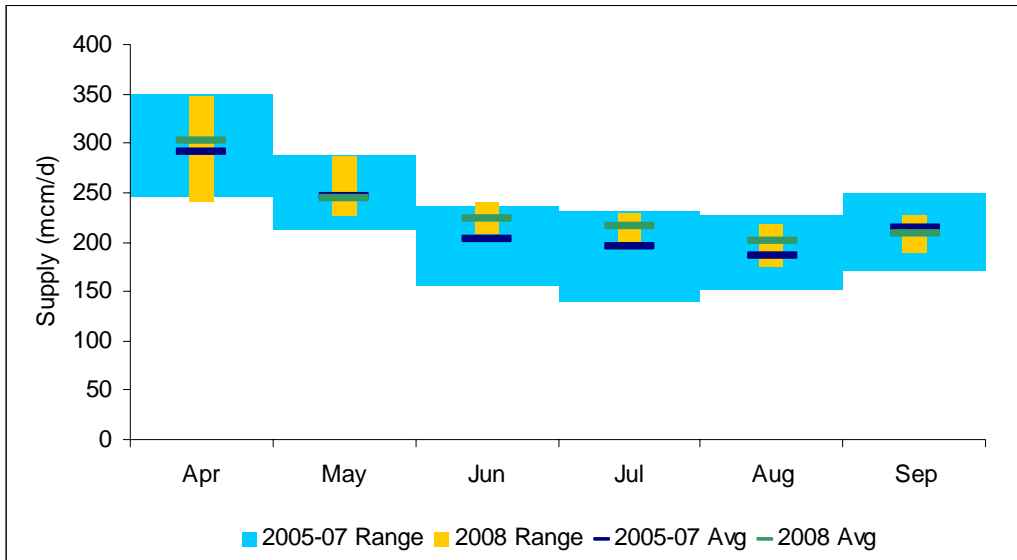


121. In terms of the choice of fuel for power generation, the chart shows a band of generating uncertainty between the areas favouring coal or gas. This arises through assumed generation efficiencies of 40% and 55%. This band passes through the gas axis rather than the origin due to the carbon price (assumed at €11/tonne) impacting coal more than gas.
122. The volatility seen in fuel prices over the past twelve months should not be discounted and a relatively small change in either fuel or carbon prices will change the relative economics of gas and coal-fired generation. This highlights the need to consider a range of gas demands for power generation this summer.
123. If gas were to be the lowest cost option for power generation, gas demand would be expected to be in the range 60-95 mcm/d. Conversely if coal were to be the lowest cost option for power generation, gas demand would be expected to be in the range 40-70 mcm/d.
124. Besides the increase in demand for power generation through a lower gas price, IUK exports could also increase unless there was also a fall in Continental gas prices.

Historic Summer Gas Supply

125. Figure G13 shows aggregated gas supplies from April to September for all supply sources from 2005 through to 2007 in terms of minimum, average and maximum demands for each calendar month. Also shown explicitly is the range and average for 2008.

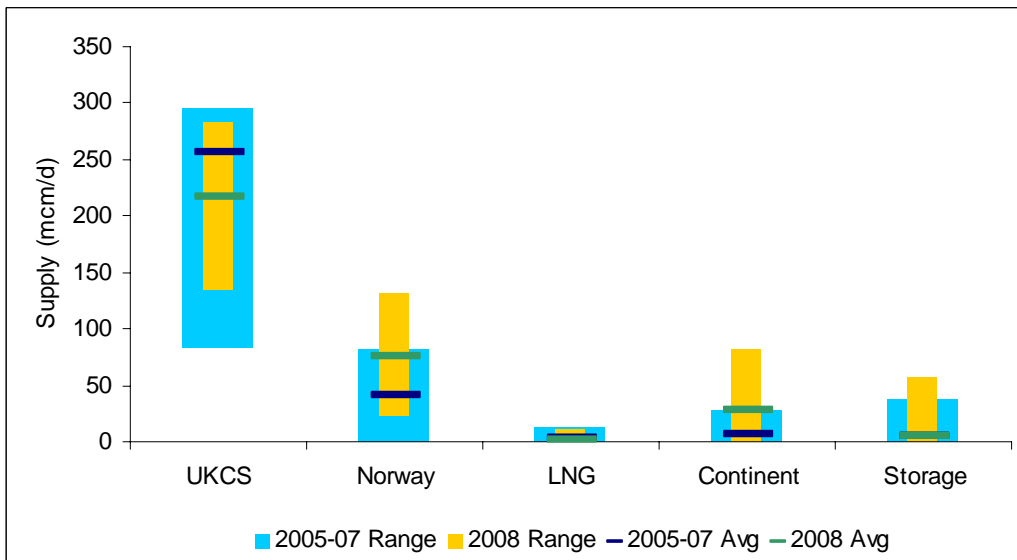
Figure G13 – Summer Supplies by Source (2005 – 2008)



126. As one would expect, the figure is similar but not identical to the total demand figure (Figure G7).

127. The range of supplies for April through to September for 2005 through to 2007 for each of the supply sources is shown in Figure G14. Also shown explicitly is the range and average for 2008.

Figure G14 – Range of Supply Sources (2005 – 2008)



128. The chart highlights considerable variations in all of the supply sources. Over the four year period minimum flows of zero have been experienced for all supply sources except UKCS. Even if the mid summer period is assessed the ranges remain considerable. The

ranges for 2008 highlight the increase in Norwegian flows primarily at the expense of lower UKCS.

129. Table G2 shows the gas supply for April to September from 2005 to 2008 for each of the supply sources in Figure G14.

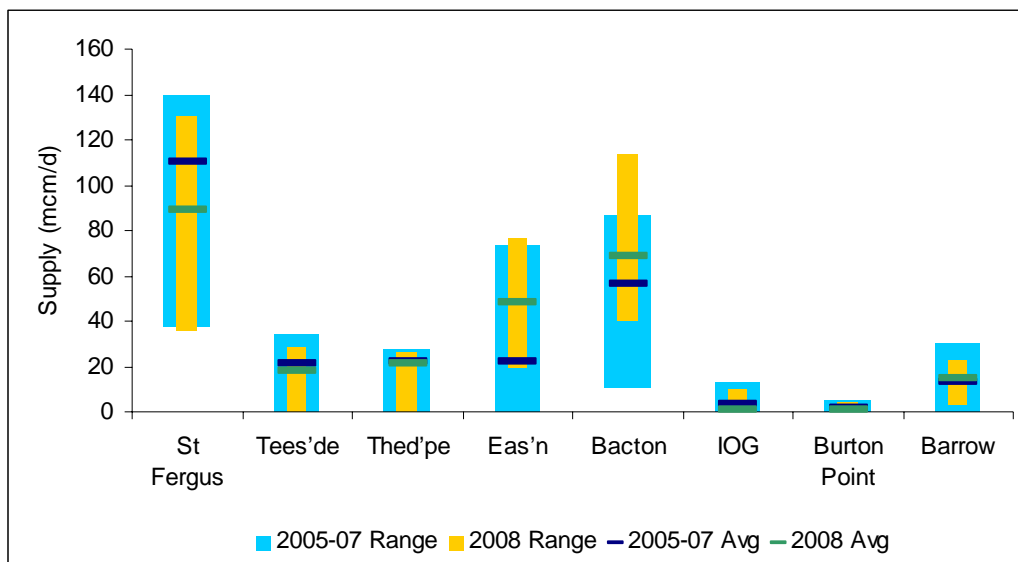
Table G2 – Summer Gas Supply by Source (2005 – 2008)

(bcm)	UKCS	Norway	LNG	Continent	Storage	Total
2005	37.0	4.1	0.1	0.1	0.4	41.6
2006	33.3	4.7	1.3	0.2	0.4	39.7
2007	30.0	7.1	0.1	2.4	0.9	40.6
2008	28.3	9.8	0.2	3.6	0.7	42.5
Average	32.1	6.4	0.4	1.6	0.6	41.1
% 2008	67%	23%	0%	8%	2%	

130. Table G2 shows aggregated April to September supplies of about 41 bcm, these are not identical to the total demands in Table 2 due to shrinkage and CV variations. The data shows supplies dominated by deliveries from the UKCS, though year on year these have declined by on average nearly 10% each year. Most of the decline in UKCS has been offset through increased imports from Norway and to a lesser extent the Netherlands through BBL.

131. The range of supplies for April to September from 2005 through to 2007 for each terminal is shown in Figure G15. Also shown is the range and average for 2008.

Figure G15 – Summer Supplies by Terminal (2005 – 2008)



132. The figure highlights considerable variations at all of the supply terminals. Over the four year period, minimum flows of zero have been experienced at all supply terminals except St Fergus and Bacton. If the

mid summer period is assessed the upper ranges are noticeably reduced for St Fergus, Easington and Bacton. The data for 2008 shows lower St Fergus flows and higher Easington and Bacton flows.

133. Table G3 shows the gas supply for April to September from 2005 to 2008 for each of the supply terminals in Figure G15.

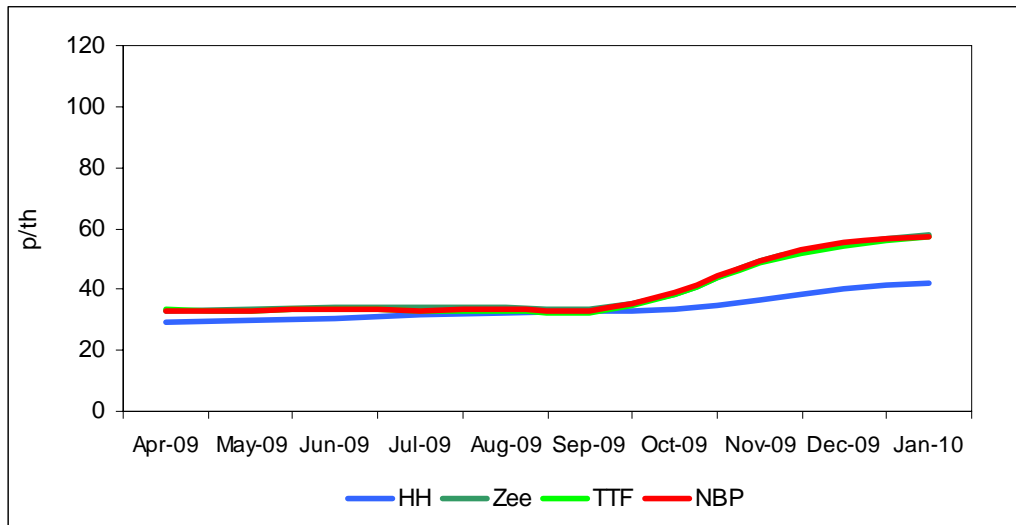
Table G3 – Summer Gas Supply by Terminal (2005 – 2008)

bcm	St F	Tees'	The'd'	Eas'n	Bac'n	IOG	B. Pt.	Bar'w	St'ge	Total
2005	19.2	3.9	3.3	2.3	9.3	0.1	0.2	3.0	0.4	41.6
2006	18.5	4.1	3.8	1.8	8.4	1.3	0.4	1.0	0.4	39.7
2007	15.4	2.3	3.6	6.6	9.3	0.1	0.2	2.1	0.9	40.6
2008	14.2	2.9	3.4	7.8	10.9	0.2	0.2	2.3	0.7	42.5
Avg	16.8	3.3	3.5	4.6	9.5	0.4	0.2	2.1	0.6	41.1
2008	35%	7%	8%	19%	27%	0%	0%	6%	2%	

134. Table G3 shows that on a volumetric basis, summer supplies have historically been dominated by deliveries from St Fergus and to a lesser extent Bacton. However supplies from St Fergus have been in decline and Easington has been higher since 2007 due to Norwegian gas being landed through Langeled.

Forecast Summer 2009 Gas Supply

135. We expect that UKCS supplies will continue to be the largest source of supply this summer, however we also expect UKCS supplies to continue to decline by 5–10% thus resulting in higher imports. To put a UKCS summer decline of 7.5% into context, this is equivalent to about 12 mcm/d.
136. There is considerable uncertainty over LNG flows to the UK this summer, this arises through numerous factors including:
- The expectation of commissioning and thereafter commencement of regular cargoes at Milford Haven from South Hook and Dragon
 - The possibility of increased availability of 'summer' LNG due to the commencement of new production sources and also from lower demand requirements in contracted markets due to the global recession
 - Competition for LNG in the Atlantic basin. Currently as shown in Figure G16, there is very little price differential between UK NBP and US Henry Hub prices. Whilst this suggests that LNG may flow to either market or possibly the nearest market, prices in both markets (notably the UK) have been subject to considerable short term variations

Figure G16 – Forward Gas Prices (20th March 2009, sources Heren & Nymex)

137. Despite the UK being a net importer of gas on an annual basis since 2004, IUK has exported every summer. We anticipate this trend will continue this summer. The markets also anticipate this as shown by the modest summer price advantage of Zeebrugge over NBP shown in Figure G16. The exceptions to IUK export conditions include:

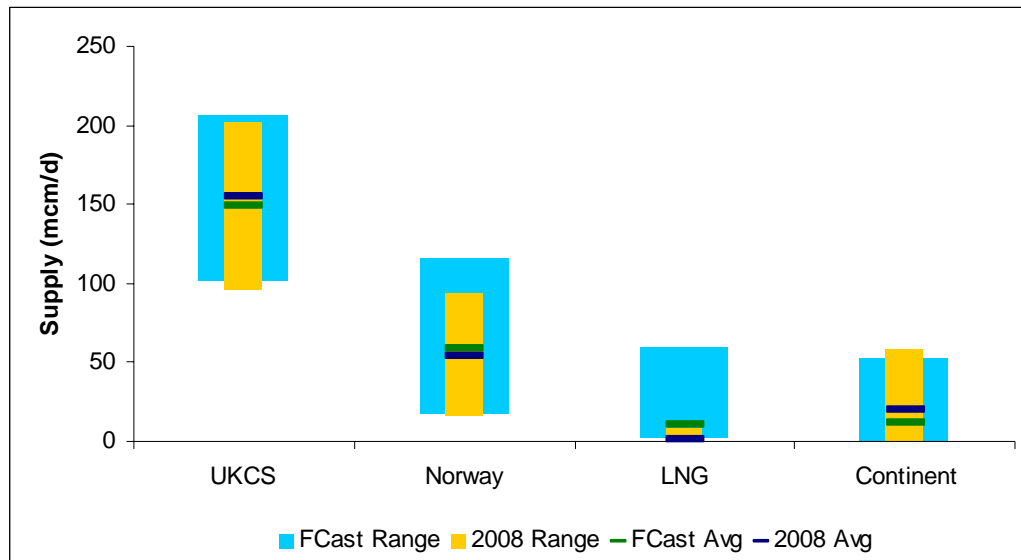
- The possibility of a UK supply shock resulting in an increase in the UK gas price
- Higher than expected UK gas demand for power generation due to the economics of gas power generation over coal
- The possibility that the economic recession on the Continent may reduce demand to a level to impact contractual take or pay obligations

138. For BBL we expect some imports during the summer. As we experienced this winter, these may become more commercially driven than previously.

139. For gas from Norway we again expect significant imports as further production from Ormen Lange is brought on stream. Norwegian imports are expected to be through a combination of Langeled, Vesterled and the Tampen Link. The economic recession on the Continent may also result in higher Norwegian imports to the UK due to flexibility in Continental contracts or prices.

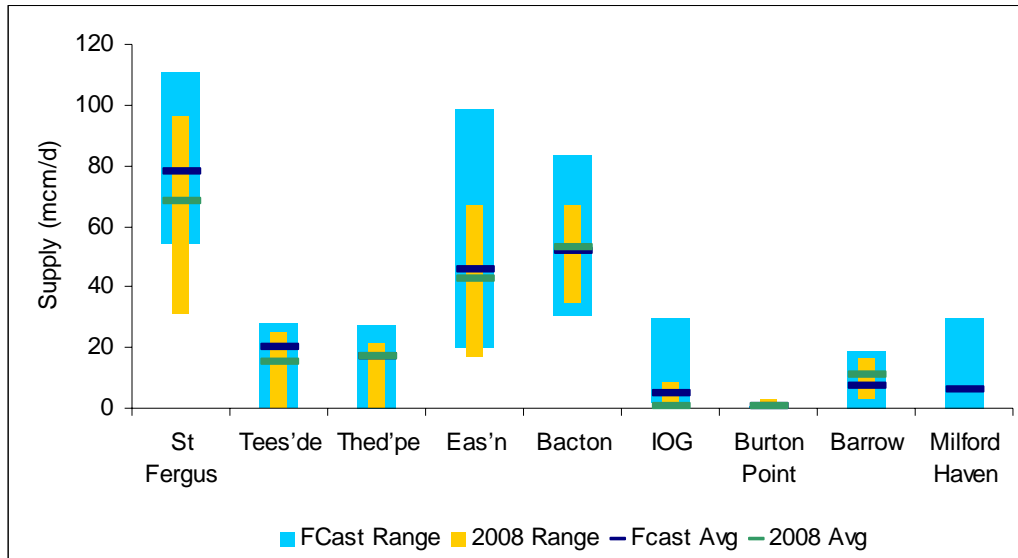
140. Figure G17 shows our forecast range of gas supply by supply source this summer. Also shown is the actual supplies in summer 2008.

Figure G17 – 2008 Summer Forecast of Gas Supply by Source



141. The chart shows considerable variation in all supply sources, notably for LNG and the Continent where forecast maximum flows are considerable higher than the forecast for average flows. Compared to summer 2008 there is little change in the forecast for average flows, though we are forecasting slightly lower UKCS and Continent being offset by higher Norway and LNG including commissioning volumes through Milford Haven. The ranges for all supply sources highlight the uncertainty associated with these forecasts.
142. The uncertainty over what supply sources will flow this summer feeds through to which entry terminals will receive gas. This uncertainty is further compounded by the fact that summer demand is typically only half that of winter demand. These factors should be taken into context for our forecast flows for this summer.
143. Figure G18 shows our terminal forecast for next summer expressed as a range for each terminal. Also shown are the actual supplies in Summer 2008. The forecasts have been derived through a combination of our annual TBE planning process (to determine the average flows for each month) and analysis of historical data since 2005 to determine the supply range. Obviously with so many permutations to make up demand, these forecasts should be considered indicative rather than explicit.

Figure G18 – 2008 Forecast of Summer Supplies by Terminal



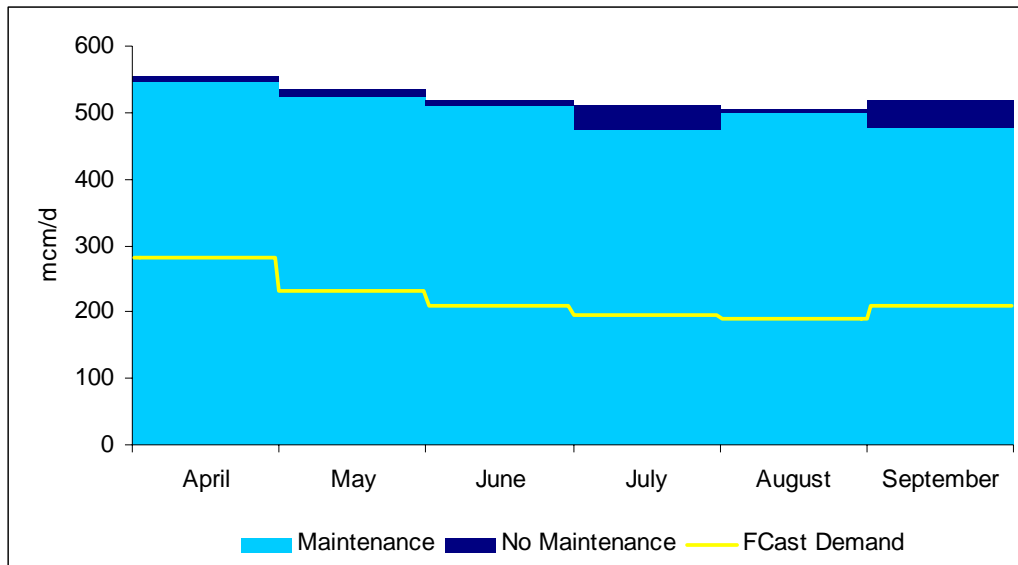
144. The chart highlights considerable variations at all terminals, though the average forecasts are not too dissimilar to those experienced in 2008. The high range for 2008 for St Fergus highlights the impact of the non-planned closure of the Forties pipeline. As detailed previously, it must be stressed there is considerable uncertainty over these forecasts.

Summer 2009 NTS Maintenance Programme and Network Capacity Expansion

- 145. To ensure a high level of safety and reliability in operation, it is essential that a system of inspection and maintenance exists for assets associated with the transmission of natural gas. Effective maintenance is essential to minimise the safety and environmental risks caused by failure of pipelines and plant.
- 146. In accordance with National Grid's Gas Transporter Safety Case, maintenance activities shall comply at all times with any statutory or legislative requirements, in order to meet legal obligations. These practices are robustly designed and seek to minimise overall operating cost by increasing the useful life of pipelines and plant, reducing the risk of failure and reducing the risk of emergency repairs.
- 147. The NTS investments delivered last summer for capacity expansion for winter 2008/9 have provided additional capacity and network flexibility. These can be summarised as follows:-
 - In Kent we completed further pipeline investment to provide additional entry capacity for the Phase II expansion at Grain which commenced flows over this winter period.

- The 245km “Trans-Pennine” pipeline was completed linking the East and West coast providing additional entry capacity in the Easington area.
 - Additional compression was added at Wormington and a new site at Felindre in South Wales as part of the overall entry capacity project for the Milford Haven LNG importation terminal. With the first ship now berthed at Milford Haven the site is now undergoing commissioning with anticipated commencement of flows to the NTS in the near future.
 - Further pipeline investment to accommodate new power station growth in the South West was also completed.
148. This summer will see the completion of an additional compression unit at Churchover for the 2009/10 winter and further progression of additional electric units at St Fergus and Kirriemuir for emissions reduction.
149. Into the future, further pipeline investment is currently being progressed for the 2010/11 winter in the South West, to provide additional exit capacity to meet forecast demand growth, and in the Easington area to provide entry capacity.
150. Further information on some of these and other expansion projects can be found at <http://www.nationalgrid.co.uk/gas/pipelines>
151. Our maintenance plan includes the impact of network reinforcement, our annual maintenance programme and supply outages. It can be found on the National Grid website at:
<http://www.nationalgrid.com/NR/rdonlyres/3E08F851-7EAC-4073-869E-60746C5A1AE1/31611/AprilMaintenanceProgSummer2009Draftv1.pdf>
152. The above document details Aggregated System Entry Points (ASEP) deliverability for each month between April and September with respect to planned maintenance and capacity expansion activities. The document also details maintenance work for each month and affected LDZs.
153. Figures G19 combines our aggregated demand forecasts and the affect of this year’s summer activities on terminal entry capacity, namely the physical capacity, at the 8 non storage ASEPs detailed in the document.

Figure G19 – The Effect of the Summer maintenance and capacity expansion programme on ASEP capability



154. The figure shows the aggregated NTS system entry capability (aggregated non storage ASEP capacities) and how this is reduced due to the summer maintenance and capacity expansion programme. The data reported are based on the lowest available capability at each ASEP for that month. Also shown on a monthly basis is the average demand forecast.

Chapter 3: Commercial Regime Developments

155. National Grid remains committed to the development of commercial arrangements that encourage timely and appropriate market responses to secure energy supply-demand balances. This chapter reflects ongoing industry discussions concerning such developments in both electricity and gas.

Electricity:

Review of constraint management on the GB Electricity Transmission System

156. On the 17th of February 2009 Ofgem wrote to National Grid asking National Grid to conduct an urgent review to consider (and if appropriate consult on) whether urgent changes to the existing commercial and charging arrangements for access to the GB transmission system are necessary before the next charging year (starting April 2009). Specifically we were asked to address:
- options for reducing the level of constraint costs; and
 - whether the current use of system charging mechanisms are equitable and appropriate.
157. Our review to date has seen a number of options being progressed:
- We have raised CUSC Amendment Proposal CAP170 which proposes to administer prices for intertrips capable of being armed in respect of derogated non-compliant transmission boundaries. Intertrips are a useful tool for National Grid as System Operator to manage constraints. Administering prices for intertrips capable of being armed in respect of derogated non-compliant transmission boundaries would offer a useful means to limit potential costs.
 - Development of Transmission Owner incentives. National Grid is working with the respective GB Transmission Owners and Ofgem to help develop an incentive designed to encourage efficient and timely investment and encourage innovation in the way the TOs plan outages.
 - We have brought forward a consultation to consider introducing a locational element to BSUoS¹⁴ charging. National Grid is presently consulting on a charging methodology proposal to fairly and equitably target the Short Run Costs (SRC) of the utilisation of transmission capacity rights on a derogated boundary. Such a price signal should enable parties to make better informed decisions as to whether it is economically efficient to pay the actual short run costs of access or adjust their generation behaviour.

¹⁴ Balancing Services Use of System

Black Start and Fuel Security Code Procedures under the Balancing and Settlement Code (BSC)

158. BSC Modification Proposal P231 aims to clarify the arrangements and obligations to be undertaken during a Black Start or Fuel Security Code (FSC) event, as currently there is no such detail in the BSC. The P231 solution outlines what is to be considered the duration of a Black Start / FSC event and the processes required to enable normal market operation.

Black Start and Fuel Security Compensation and Single Imbalance Price Derivation

159. BSC Modification Proposal P232 seeks to improve transparency regarding the compensation arrangements pursuant to a Black Start or FSC event. The BSC provides high level details of the compensation arrangements associated with a Black Start or FSC event, however, certain areas require further clarification. P232 will address these areas by recommending more detailed processes and procedures

Transmission Access Review

160. CUSC amendment proposals CAP161-166 have now been assessed by the CUSC Amendments Panel and are with Ofgem for decision. Consultation documents on some of the associated charging changes will be also published over the next few weeks.
161. At the February meeting of the CUSC Amendments Panel a further access related Amendment Proposal was raised by ConocoPhillips. Due to the relationship between this proposal, CAP168: Transmission Access – Under-use and reallocation of TEC, and those described above, it has been granted urgent status. It will be considered by a Working Group for a period of one month prior to progressing to further industry consultation.

Gas:

Introduction of Enduring NTS exit capacity arrangements

162. On 19 January 2009 Ofgem approved UNC Modification Proposal 0195AV which will be implemented 01 April 2009 and introduces Enduring NTS offtake arrangements from 01 October 2012. Current arrangements allow Users to secure capacity until 30 September 2012.
163. As part of these arrangements
- Users can apply for Enduring capacity in the Annual July Application Window or via an Ad-hoc process
 - Developers can apply for Enduring capacity via the ARCA process.
 - A standard 4 year User Commitment is applied to Enduring capacity requested from 01 April 2009
 - Annual, Daily and Offpeak capacity can also be procured before the start of the Enduring regime.

- For further detail please refer to a dedicated exit reform section of our website
www.nationalgrid.com/uk/Gas/OperationalInfo/endureexitcap/

Substitution

164. Ofgem introduced an obligation for National Grid to undertake Entry and Exit Capacity Substitution.
165. Under the Entry obligation National Grid will seek to substitute unsold Non-incremental obligated Entry Capacity to other entry points where Incremental obligated Entry Capacity is required to be released.
166. National Grid has been consulting with the Industry and Ofgem to identify the most appropriate way to introduce Entry Capacity Substitution. Regular workshops are being held to explore potential Entry Capacity Substitution options required to address Industry concerns and meet the aims of the Substitution obligation. The Entry Capacity Methodology Statement is to be submitted to Ofgem by 7th September 2009.
167. Under the Exit obligation, substitution would only apply to capacity from 1 October 2012 onwards i.e. the enduring period. National Grid has a licence obligation to submit an Exit Capacity Substitution Methodology Statement to the Authority by 1 April 2009 and has requested a derogation to this.

Amendment to QSEC and AMSEC Auction timetables

168. Modification 0230 has been proposed to move the QSEC Auction from September to March. This would result in Incremental NTS Entry Capacity being released from 1 October at the start of the winter period when flows increase. In order for QSEC and AMSEC not to overlap it is also proposed that the AMSEC auction is moved to June. An alternative Mod has been raised which includes a September 2009 QSEC before moving the QSEC to March on a permanent basis. The alternative also retains the AMSEC in February but shortens the transaction period from the current 2 years to 18 months. Both these proposals have been submitted to Ofgem for a decision.

Operating Margins contestability

169. UNC Modification 0240 – “Promoting Competition in Operating Margins Provision” has been approved by Ofgem. This modification introduces and facilitates flexibility in the procurement of Operating Margins (OM) services from providers other than storage operators and LNG terminals. Over the next 12 months National Grid Transmission will work with successful tender parties to investigate the potential for future OM provision from non storage System Points with a view to submitting a revision to the Transmission Safety Case to the HSE for approval.

UNC Review Group 0221 - Review of Entry Capacity and the Appropriate Allocation of Financial Risk

170. Review Group 0221 is seeking to introduce financial underpinning of Entry Capacity bookings and subsequently reduce the economic risk to gas consumers from shipper “default”. This Review Group is due to report to the UNC Modification Panel in April 2009 with UNC Modification Proposal(s) taken forward as an outcome of this review.

Review of the UNC Post-Emergency Arrangements

171. In February 2009, National Grid initiated an industry review of the prevailing UNC post-emergency arrangements. The objective of the review is to consider primarily what UNC changes could be made to the post-emergency claims process that would improve the definition and give greater clarity in this area. It is anticipated that any such changes would provide further confidence to shippers that they would be able to recover their costs for providing additional supplies and/or demand side reduction following a Network Gas Supply Emergency (Gas Deficit Emergency).
172. Subject to the outcome of this review National Grid will raise a UNC Modification Proposal with a potential implementation date of October 2009.

Appendix I – Forward Prices¹⁵

1) GB Power Prices

€/MWh	Week Ahead (wc 23/03/09)	Month Ahead (April)	Quarter 2 2009	Quarter 3 2009	Summer 2009	Winter 2009/10
Baseload	34.25	34.25	34.75	35.75	35.25	45.10
<i>Change</i>	-0.77	-0.75	-0.42	-0.10	-0.27	-0.65
Peaks	39.13	39.40	40.90	45.05	42.98	55.65
<i>Change</i>	-0.98	-1.50	-0.58	1.55	0.48	-1.43
Off-Peaks	31.54	31.39	31.33	30.58	30.96	39.24
<i>Change</i>	-0.66	-0.33	-0.34	-1.02	-0.69	-0.22

2) Gas Prices (assuming 49.13% efficient plant)

NBP	Week Ahead (wc 23/03/09)	Month Ahead (April)	Quarter 2 2009	Quarter 3 2009	Summer 2009	Winter 2009/10
p/therm	32.00	32.75	32.65	32.75	32.50	52.00
<i>Change</i>	1.40	2.75	2.70	2.55	1.75	1.30
€/MWh e	22.22	22.75	22.68	22.75	22.57	36.11
<i>Change</i>	0.97	1.91	1.88	1.77	1.22	0.90

3) Exchange Rates

	£ to €	£ to \$
	0.936	0.691
<i>Change</i>	0.013	-0.018

4) Coal Prices (assuming 36% efficient plant)

ARAcif	Week Ahead (wc 23/03/09)	Month Ahead (April)	Quarter 2 2009	Quarter 3 2009	Summer 2009	Winter 2009/10
\$/tonne	60.80	59.25	60.25	63.50	61.88	70.25
<i>Change</i>	2.85	2.25	6.00	4.50	5.25	3.67
€/MWh e	16.74	16.32	16.59	17.49	17.04	19.35
<i>Change</i>	0.37	0.21	1.26	0.82	1.04	0.53

5) Carbon Prices

	€/metric tonne	€/MWh e Gas	€/MWh e Coal	€/MWh e Oil
2009	11.35	4.36	9.99	9.14
<i>Change</i>	-1.05	-0.34	-0.77	-0.71
2010	11.85	4.55	10.43	9.54

¹⁵ Analysis based on prices on 23rd March 2009.

<i>Change</i>	-1.00	-0.32	-0.72	-0.66
2011	12.60	4.84	11.09	10.14
<i>Change</i>	-1.10	-0.35	-0.80	-0.73

6) Clean Spark Spreads

£/MWh e	Week Ahead (wc 23/03/09)	Month Ahead (April)	Quarter 2 2009	Quarter 3 2009	Summer 2009	Winter 2009/10
Baseload	7.67	7.15	7.72	8.65	8.32	4.53
<i>Change</i>	-1.41	-2.32	-1.96	-1.53	-1.15	-1.23
Peaks	12.54	12.30	13.87	17.95	16.05	15.08
<i>Change</i>	-1.61	-3.07	-2.11	0.12	-0.40	-2.00
Off-Peaks	4.96	4.29	4.30	3.48	4.03	-1.33
<i>Change</i>	-1.30	-1.91	-1.88	-2.45	-1.57	-0.80

7) Clean Dark Spreads

£/MWh e	Week Ahead (wc 23/03/09)	Month Ahead (April)	Quarter 2 2009	Quarter 3 2009	Summer 2009	Winter 2009/10
Baseload	7.52	7.95	8.17	8.28	8.22	15.55
<i>Change</i>	-0.37	-0.19	-0.92	-0.14	-0.54	-0.43
Peaks	12.40	13.10	14.32	17.58	15.95	26.10
<i>Change</i>	-0.57	-0.94	-1.07	1.51	0.21	-1.21
Off-Peaks	4.81	5.09	4.76	3.11	3.93	9.69
<i>Change</i>	-0.26	0.23	-0.83	-1.06	-0.96	0.00

8) Clean Fuel Spreads (+ve = Gas higher in Merit than coal)

£/MWh e	Week Ahead (wc 23/03/09)	Month Ahead (April)	Quarter 2 2009	Quarter 3 2009	Summer 2009	Winter 2009/10
Spread	0.15	-0.80	-0.45	0.37	0.10	-11.01
<i>Change</i>	-1.04	-2.13	-1.05	-1.39	-0.61	-0.79

9) French Power Prices

£/MWh	Week Ahead (wc 23/03/09)	Month Ahead (April)	Quarter 2 2009	Quarter 3 2009	Summer 2009	Winter 2009/10
Baseload	32.76	32.39	29.48	31.12	30.30	52.63
<i>Change</i>	-2.54	-0.15	-0.05	0.52	0.24	0.82
Peaks	40.25	40.44	39.03	43.52	41.28	70.76
<i>Change</i>	-4.29	-0.04	1.00	0.24	0.62	0.89
Off-Peaks	28.60	27.91	24.18	24.23	24.21	42.55
<i>Change</i>	-1.58	-0.21	-0.64	0.69	0.02	0.79

10) GB vs French Spreads

	Week Ahead (wc 23/03/09)	Month Ahead (April)	Quarter 2 2009	Quarter 3 2009	Summer 2009	Winter 2009/10
Baseload	1.49	1.86	5.27	4.63	4.95	-7.53
<i>Change</i>	<i>1.77</i>	<i>-0.60</i>	<i>-0.37</i>	<i>-0.62</i>	<i>-0.51</i>	<i>-1.47</i>
Peaks	-1.12	-1.04	1.87	1.53	1.70	-15.11
<i>Change</i>	<i>3.31</i>	<i>-1.46</i>	<i>-1.58</i>	<i>1.31</i>	<i>-0.14</i>	<i>-2.32</i>
Off-Peaks	2.94	3.48	7.15	6.35	6.75	-3.31
<i>Change</i>	<i>0.91</i>	<i>-0.12</i>	<i>0.30</i>	<i>-1.70</i>	<i>-0.72</i>	<i>-1.01</i>