Transmission Price Control Review

2007-2011

Technical Advice on

Supply & Demand Forecasting

And Forecast Capex

Final Draft Report

Issue 5

12th October 2006

List of Revisions

Version	Date	Pages Affected	Revision History
TPA TPCR Supply/Demand Forecasting and Future Capex Plans First Draft Issue 1	13.3.06	All	First Draft Report Issued to Ofgem (Supply and Demand Review)
TPA TPCR Supply/Demand Forecasting and Future Capex Plans First Draft Issue 2	28.03.06	Exec.Summ.	Exec.Summ.revised following Ofgem comments
TPA TPCR Supply/Demand Forecasting and Future Capex Plans First Draft Issue 3	13.04.06	Section 5	Addition of Section 5 dealing with Forecast Capex Review
TPA TPCR Supply/Demand Forecasting and Future Capex Plans Section 5, v1	15.04.06	Section 5 only	Addition of Section 5 dealing with Forecast Capex Review
TPA TPCR Supply/Demand Forecasting and Future Capex Plans Section 5, v2	21.05.06	Updated Section 5	Following further information from National Grid
TPA TPCR Supply/Demand Forecasting and Future Capex Plans Final Draft Issue 1	2.6.06	Revisions throughout	Update and Revisions throughout, to reflect information received
TPA TPCR Supply/Demand Forecasting and Future Capex Plans Final Draft Issue 2	23.06.06	Exec Summary and Section 5.8	Changes to figures in forward capex section 5.8, Executive Summary Section 1 re-drafted. Minor changes to 4.5.2.2, 5.6.6, 5.6.8 & 5.7
TPA TPCR Supply/Demand Forecasting and Forecast Capex Final Draft Issue 3	6.7.06	Revisions Throughout	Changes finalising notes and updating where responses have been received from National Grid. Slight title change.
TPA TPCR Supply/Demand Forecasting and Forecast Capex Final Draft Issue 4	18.7.06	Minor Corrections	See Erratum List for Issue 3
TPA TPCR Supply/Demand Forecasting and Forecast Capex Final Draft Issue 5	12.10.06	Minor Amendments	Updated for revised Compressor Running hours [redacted]. Appendices completed

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[redacted]

SECTION 1. EXECUTIVE SUMMARY

TPA Solutions were appointed to provide technical support in relation to Ofgem's work on the forthcoming Price Control Review (PCR) of National Grid, for the Gas Transmission part of the business, specifically to:

- Review the supply forecasting process, methodology and input assumptions and to produce a central case supply forecast with sensitivities
- Review demand forecasting process, methodology and input assumptions and to produce a central case demand forecast with sensitivities
- Review the supply demand matching methodology
- Review the NGGT investment plan and examine the efficiency of planned project execution and produce an independent capex forecast

TPA Solutions ('TPA') has been engaged separately to review National Grid's Historical Capex and Opex expenditure for the period 2002 to 2005 and proposals for Forecast Opex for the period 2005 - 2012. The report on that work is provided in Transmission Price Control Review – Efficiency Study. All figures have been expressed in 2004/2005 prices unless otherwise stated.

The summary conclusions of our review are set out below:

1.1 Supply/demand processes and methodology

- Whilst the supply and demand forecasting methodologies have remained broadly the same for at least the last five years, there has been an evolution of the methodologies to accommodate market developments including broadening the scope of its analysis in order to develop the supply forecasts as a result of the wider interaction of the UK market with European and US markets. TPA supports the approach and methodology

- The UKCS forecasting process is based on gathering intelligence from the producers and supplementing this with other sources of data. In principle this is a reasonable approach to developing a view of potential annual gas supply availability. However, TPA believes that this approach may not capture the possible changes in output and seasonality from the UKCS and have presented in this document an alternative scenario for UKCS supplies. This scenario assumes a different seasonal supply profile in the medium term (once the current high price spike has passed) with the UKCS operating on a reduced load factor by delivering a lower proportion of the total annual volume in summer compared to current practice.

- TPA has paid particular attention to the SW LDZ demand forecasts as this is an area where specific LDZ demand lead investment has been highlighted. There are a number of specific assumptions that TPA has reviewed relating to the impact of household appliance efficiency, energy price, calorific value and demand management. The impact of energy price was of particular note as a result of the dramatic increase in gas prices and higher long term oil and gas price forecasts compared to 12 months ago (base period for FBPQ). These higher prices will result in lower forecast growth.

- National Grid has argued that there is going to be increased uncertainty regarding supply sourcing in the next PCR period. However, whilst National Grid is making significant investments to accept new supplies at Milford Haven, Isle of Grain, Bacton and Easington, it has made no specific capex proposals related to the increased uncertainty, though it has maintained the 5% flow margin for all the entry related schemes currently underway. TPA believes that there will be significantly less reliance on UKCS supplies and St Fergus in particular than in the past 10 years, and that the more diverse supply pattern is significantly more favourable from a network operators perspective with major new sources of gas and flexibility closer to sources of demand than in the past.

- TPA believes that the flow margin utilised by National Grid in their network analysis, to accommodate specific uncertainties in forecasts and designated operational difficulties, should be reviewed in the light of recent developments.

1.2 Forecast Capex

The following table summarises TPA's findings for forecast Capex

Capex area (figs for 7 year period)	**TPA Commentary**
Baseline ([redacted]) - £357M	Good business case
Baseline – new entry points ([redacted]) – approx £584M	Good business case, unit costs very high but process for delivery is generally not inefficient
Increased capacity above Baseline – ([redacted]) - £81M	Good business case, unit costs very high but process for delivery is generally not inefficient
[redacted] – [redacted] - £120M	Good business case, unit costs very high but process for delivery is generally not inefficient
Unit costs generally - £41m	'EC Harris' costs apply mostly to [redacted] and [redacted] demand projects and so saving could be around **£31M** if these projects are not progressed or delayed (see 5.8.3 below, note 3)
[redacted] - £170M	TPA recommends that National Grid and Ofgem use the [redacted] load growth/NTS capacity issue in order to inform the shipper community in relation to load growth (higher gas prices), Exit Reforms, Flow Margin and Constrained LNG at [redacted] with the prize being that none of the forecast [redacted] projects are built. TPA believes that Ofgem should consider an SO incentive on National Grid in order to achieve this [redacted] Given the uncertainty related to gas prices and the above factors, TPA believes that as a central scenario, [redacted] growth should be reduced by **£68.3M** (capex in last 2 years of the next PCR period)
[redacted] – [redacted] - £157M	TPA does not believe that National Grid has demonstrated a business case for this investment ([redacted])
[redacted]	[redacted]
IPPC - £253M *	[redacted]

	[redacted] In addition, subject to technical evaluation, relocation of machines may save **£7.5-10M**, giving a total possible reduction in IPPC related capex of **£52.3M – 54.8M** in next PCR period
Serviceability - £145M *	Reduction of **£29.5M** plus any savings due to relocated assets (**£7.5- 10M)**
[redacted] - £28M	Possible saving of **£0 -23M**
West Sole compression	Seems reasonable (TP4180 to be reviewed)
Other non load related -	Environmental standards case is weak in FBPQ narrative – possible - **£5 – 10M** reduction

***** *Additional capex is likely to be required in these areas in the event of successful entry capacity bids in the September 06 long term auctions for* [redacted] *entry points.*

Financial Summary

Area	**Potential increase/reduction Compared to FBPQ (2007/8-2011/12) £M**	
National Grid FBPQ	1448	1448
National Grid FBPQ – Projects Not Yet Approved by National Grid	758	758
	Lowest capex	**Highest capex**
National Grid revised capex forecasts for approved pipeline and Milford Haven compressor projects **Note 1 and Note 2**	+218.1	+218.1
Exit – [redacted]	-157	-157
Exit – SW load growth	-137	-68.3
EC Harris Unit Costs **Note 3**	-31.8	-31.8
IPPC – extent of programme	-51.6	-51.6
IPPC – use of relocated assets **Note 4**	-10	-7.5
Asset repex – extent of programme	-29.5	-29.5
Asset repex – use of relocated assets **Note 4**	-10	-7.5
Other major capex	-23	0
Other non load related (Enviro Standards)	-10	-5
Total TPA reduction	**-459.9**	**-358.2**
TPA reduction less National Grid increase – ie TPA net reduction	**-241.8**	**-140.1**
Total TPA net reduction as % of National Grid FBPQ	16.7%	9.7%
Total TPA reduction as % of National Grid FBPQ – Not Yet Approved	31.9%	18.5%

[redacted]

Notes

1. National Grid has indicated significant higher costs for most approved projects, key increases as follows:

Increases in Project Costs (TP4162)

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
				[redacted]	[redacted]	[redacted]

Source: National Grid

TPA's view is that there are reasonable grounds for the higher revised capex forecasts as a result of individual project circumstances and market conditions.

[redacted].

3. TPA understands the EC Harris increases apply to unapproved pipeline projects. [redacted]

[redacted]. As a result, the EC Harris costs are reduced to £9.6M. See sheet 10 in the master spreadsheet (reduction of 31.8)

4. TPA believes it may be possible to save £15 – £20M capex by relocating IPPC approved compressor assets that are no longer required, this reduction is allocated between IPPC and Repex.

Additional Information

National Grid provided updates to the 05/06 figures (i.e. actual figures) in September 2006. The most material items in these updates were increases (relative to the original submission) of £4.4M in the costs for South West Reinforcement and £18.1M for the Felindre to Tirley pipeline. Other minor adjustments relative to the original submission were made including an overall £3.6M decrease in costs of compressor projects, and a decrease of some £4m for the other capital project costs. These figures have not been updated in this report, because TPA has not received revised forecast figures for 06/07. [redacted]

SECTION 2. INTRODUCTION

This report has been commissioned to provide Technical Consultancy Support to Ofgem for the Transmission Price Control Review. [redacted]. The report is designed to assist Ofgem in assessing the reliability of the supply and demand forecasts that underpin the forecast growth investment in the NTS and to assess the efficiency of all forecast capex to be incurred during the period 2005 – 2011.

The report is intended to inform Ofgem's proposals to be made in summer 2006 for revised gas transmission revenue controls to be effective from April 2007.

The contract for this work was won at open tender by TPA Solutions Limited. TPA Solutions ('TPA') has not engaged subcontractors for this work, although it has engaged experts to advise on certain areas (for example Network Planning & Modelling and Compression). We have worked together as one team and each author has read the contributions of the others.

2.1 Scope and Objectives

[redacted]

Our scope has covered:

- the supply and demand forecasts that influence investment in the National Transmission System which involves assessment of all UKCS supplies, all UK imports and exports and UK gas demand growth and
- the forecast capital expenditure associated with the National Transmission System.

The objectives of our work on have been as follows (reproduced from the ITT):

Gas Supply Forecasting

- To understand and assess the supply forecast process and methodology adopted by NGGT;
- To assist Ofgem to make informed judgement of the NGGT supply assumptions for 2005/06 – 2011/12;
- To establish a Central Case for gas inputs into the NTS (in effect the 'supply' forecast); and
- To develop sensitivities around the Central Case.

Gas Demand Forecasting

- To understand and assess the demand forecast process and methodology adopted by NGGT;
- To assist Ofgem to make informed judgement of the NGGT demand assumptions for 2005/06 – 2011/12;
- To establish a Central Case for gas transportation requirements on the NTS (in effect the 'demand' forecast); and
- To develop sensitivities around the Central Case.

Assessment of gas transmission capex for 2005/06 – 2011/12

- To assess the efficiency of NTS investment plan for 2005/06 -2011/12 proposed by NGGT; and
- To provide an independent view on efficient level of capex required and associated outputs for the next price control period.

2.2 Process

National Grid and Ofgem agreed a formal process for request and provision of information and TPA Solutions has taken care to adhere to this process at all times. This is the first time that gas and electricity price control reviews have been undertaken simultaneously. Other consultants have been engaged by Ofgem to review other aspects of National Grid's business, and National Grid and Ofgem co-ordinated all our information requests through one process. We recognise that National Grid have devoted a significant effort to collating data, providing presentations to us and answering our questions. [redacted]

During September/October 2005, National Grid prepared a response to Ofgem's Forecast Business Plan questionnaire (FBPQ). At the outset of our study (the middle of December 2005) TPA reviewed the FBPQ documents in detail, and submitted an initial list of 38 questions, including requests for more detailed information such as more detailed data on the supply and demand forecast assumptions and methodologies. During our study we have submitted a total of 159 additional questions and received written responses to all of these. [redacted]

National Grid have stated that some of the information that we have requested is either unavailable at the level of detail we have requested as in the case of field specific supply data, or is only available through another party [redacted]

TPA Solutions have acquired an independent set of supply and demand forecasts which are included in this report, together with a TPA forecast that makes certain alternative assumptions with respect to the UKCS and imports and presents an alternative approach to scenario development.

We are grateful to Ofgem staff for their support throughout our data gathering, analysis and in the preparation of this report.

The report is structured as follows:

- Section 1 is the Executive Summary
- Section 2 is the Introduction
- Section 3 provides an overview of the National Grid supply and demand forecasting methodology and the forecasts provided over the period 2005/ to 2011/12.
- Section 4 provides comparisons between National Grid forecasts and those from TPA and Energy Contract Company
- Section 5 provides our review of forecast capex.

[redacted]

SECTION 3. SUPPLY AND DEMAND FORECASTS 2005/6-2011/12

TPA Solutions Limited have carried out a thorough review of the gas supply and demand forecasting process at a level of detail that is necessary for Ofgem to establish that decisions on the reinforcement of the NTS are made with the most reliable data available to National Grid. The responsibility for the forecasting process is split between supply and demand with the matching process being carried out by the supply team.

This report examines the two distinct forecasting processes in logical order, with the annual demand process being the starting point followed by the peak process (primary driver of NTS exit investment). The annual and peak supply process is then reviewed and finally the supply demand match is included as an integral part of the supply demand forecasting process (and ultimately the driver of entry investment).

3.1 Demand forecasts 2005/6-2011/12

3.1.1 Methodology

3.1.1.1 Annual Demand Forecasts

The description provided by National Grid of the annual gas demand forecasting process has been summarised as follows:-

The development of annual gas demand forecasts considers a wide range of factors, from complex econometrics to an assessment of individual load enquiries. For any forecasting process a set of planning assumptions is required, which if necessary can be flexed to create alternative scenarios. In the case of the forecasts presented in the FBPQ document, assumptions include economic, fuel prices, environmental and tax policies, etc. A number of these assumptions are based on data from independent organisations. The forecasts are also benchmarked against the work of a number of recognised external sources, such as the DTI.

The way the assumptions are utilised and the modelling approach adopted are different when applied to the LDZ and NTS forecasting processes.

a) LDZ Modelling

LDZ demand is split into four market sectors according to load size and supply type (i.e. firm or interruptible). For each sector models have been developed that make allowance for economic conditions, local demand intelligence, new large load enquiries, relative fuel prices, potential new markets and other factors, such as the Climate Change Levy, that could affect future growth in demand.

By adopting this approach NG take account of varying economic conditions and specific large loads within different LDZs

b) NTS Modelling

The methodology adopted depends on the type of load connected to the NTS.

c) Power Generation

The power generation forecast consists of two main elements, firstly, the capacity available to generate and secondly, how frequently this capacity is in operation.

The first element is developed by comparing information from connections requests and load enquiries with feedback received from the Transporting Britain's Energy (TBE) consultation process and a range of commercial sources. In addition, the influence of commercial arrangements, Government policies and legislation are taken into account when deciding which power stations will be built or closed. The processes employed in this area of the forecast by National Grid are common with those applied to develop the forecasts of generation appearing in the National Grid Seven Year Statement for the Electricity Transmission System.

To complete the second element, a model has been developed that forecasts the demand for electricity generation by fuel type and individual station over the forecast period. The modelling process takes account of station specific operating assumptions, constraints, costs and availability. Actual station data is also used to support the process.

The resultant power generation forecast, encompassing all fuel types, is then used to derive a split between gas-fired stations supplied by the NTS (or embedded within the DNs) and those with their own dedicated pipeline delivering supplies direct from the beach.

d) Exports

Forecast flow rates to and from Europe via the Interconnector are based on an assessment of relative gas prices between Europe and the UK, allowing for the seasonal variation of gas prices and resultant price differentials. [redacted]

Exports to Ireland are derived from a 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.

e) Industrials

The production of forecasts within this sector is dependent on forecasts of individual new and existing loads based on recent demand trends, TBE feedback, load enquiries and commercial sources.

3.1.1.2 Seasonal and Peak Demand Forecasts

a) Demand/Weather Modelling

In order to meet both the demand estimation requirements of the Network Code and planning requirements for forecasts of demand in future years, a consistent methodology for demand/weather modelling has been developed by National Grid in conjunction with network users. Under this methodology, all demand models (whether for LDZ demand or for categories of NDM demand as required under the Network Code) are based on Composite Weather Variables (CWVs) defined and optimised for each LDZ. Details of the modelling approach, definitions of CWVs and current CWV parameters are provided in the National Grid document "NDM Profiling and Capacity Estimation Algorithms for 2004/5". This document is however only available to Network Code signatories. Seasonal normal CWVs (one for each day and each LDZ) are produced in accordance with the rules set out in the Unified Network Code, using a 17-year historical weather database. This period has recently been changed from a 35 year basis. An explanation of the reasons for this was provided by National Grid [redacted]

National Grid still maintains that there is no evidence that supports an adjustment to the peak methodology to take account of global warming.

b) Peak Day Demand Modelling

Having developed the annual demand forecasts and daily demand/weather models National Grid use a complex simulation methodology, taking historical weather data from the last 78 years for each LDZ, to determine the peak day. This methodology is in accordance with their statutory/Licence obligations. In addition severe winter demand estimates are produced. Where possible, the peak day demand of the NTS supplied loads, such as the power stations, is based on the contractual commitment that National Grid have made at the specific exit point. Export demands are treated slightly differently. The European Interconnector is assumed not to be exporting at times of peak demand, on the basis that the UK market will always attract peak gas from Europe to meet demand due to the high price of UK gas in the winter. Irish demand is derived from National Grid's own market-sector based analysis.

The peak day import assumption from Europe is not necessarily sustainable however, given the potential large surpluses of gas in the market.

3.1.2 Forecast assumptions

The key market assumptions used by National Grid in developing their forecasts of gas demand are:

- Economic growth averages around 2.6% per annum over the period – supported by relatively strong service sector growth, whilst manufacturing only grows by 1.5% per annum. The rate of inflation remains steady.
- Higher wholesale gas prices in the early years, driven by relatively high oil prices compared to 2000 – 2003 period ($35/bbl) and a tight supply-demand position (Note – the gas prices used by National Grid now appear, in 2006, to be below the bottom end of forecasts as a result of the upward move in consensus gas and oil price forecasts)
- Lowering of wholesale gas prices in the later years as new supplies and import facilities are developed.

National Grid take in a range of externally sourced forecasts and forward price curves, but then utilise their own interpretation of these figures to develop their own view of fuel price movement.

The impact of these assumptions on the demand forecasts are summarised from the National Grid FBPQ as follows.

- Demand from the distribution networks (DN) is affected in the early years by the high wholesale gas prices, with the energy intensive manufacturing sector the most affected. In the later years of the forecast, DN demand rises as the wholesale price falls due to increasing supplies.
- Twelve new gas fired power stations are forecast to be developed over the period to 2015, comprising 12.4GW of generation capacity, with six stations comprising 4.8GW of generation commissioned by 2012. These developments are required due to the closure of 7.6GW coal fired generation as a result of the large combustion plant directive (LCPD), and 3.4GW of nuclear plant which reaches the end of its life. CHP growth forecasts are similar to last year with only 7GWe in 2010, falling short of the Government's 10 GWe capacity target. Disincentives to installing CHP include volatility in the relative prices of gas and electricity and the requirement to purchase additional carbon credits to offset the extra gas burnt to generate electricity.

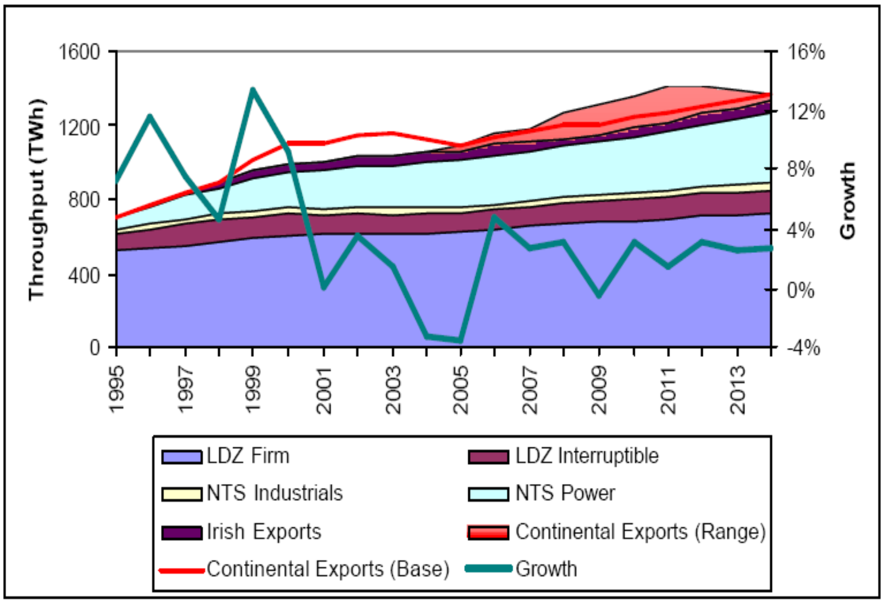
The exports market is made up of the demands of the Irish and Bacton-Zeebrugge interconnectors. In the forthcoming Price Control period, the flow of gas to Continental Europe is expected to remain seasonal, with significant exports during the summer, with flows being dependent on the daily price differentials between the UK and Continental Europe. Demand for gas in Ireland is expected to grow strongly over the forecast period, particularly due to developments in the power generation sector, although the development of the Corrib field will reduce the export demand placed upon the NTS in the mid to long-term. Nevertheless, there remains a fair degree of uncertainty associated with all new supplies. Due to the influence that power generation has on the Irish market, any factors impacting upon existing demands, or the scale and timing of new gas-fired developments, will tend to have an effect on the accuracy of the forecast. Although growth in the Irish economy has slowed recently, it is forecast to increase over the forecast period, with the rate of growth being the significant forecast sensitivity.

3.1.3 Summary of Demand Forecasts

3.1.3.1 Annual Throughput

National Grid are forecasting that gas demand is projected to grow at a rate of 2.2% per annum to 2014 with DN demand growing at 1.7% per annum and NTS demand forecast to grow at an average of 3.2% each year. The NTS growth rates are forecast to be more volatile due to the uncertainty surrounding their assumptions regarding the profile of exports. Figure 1 below shows the historic demand levels provided by National Grid back to 1995 for comparison with their annual demand forecast.

Figure 1 : Historic Demand Levels



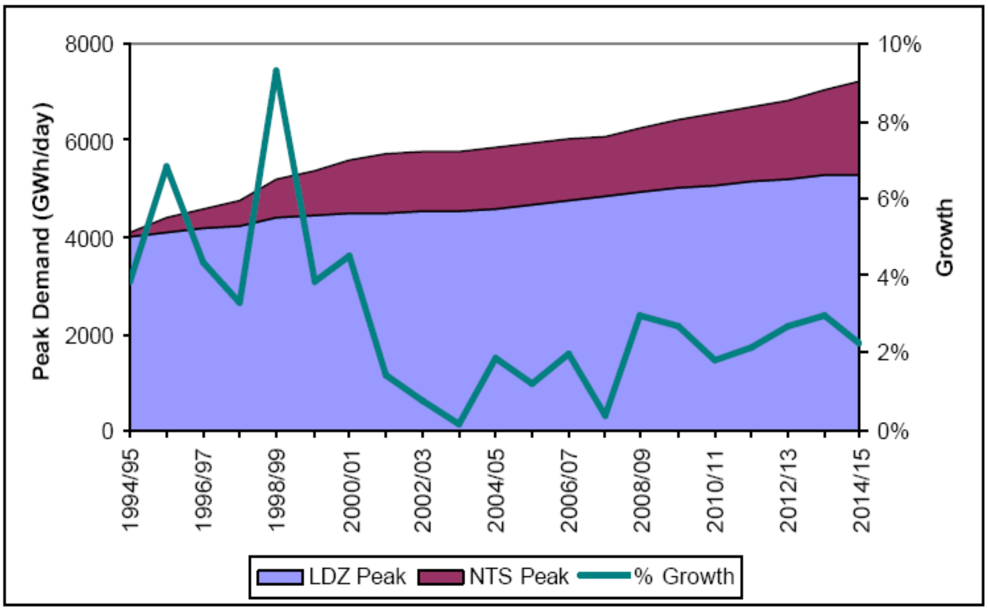
Source: National Grid

National Grid present a range of possible Continental exports, alongside their base case, to illustrate the effect this may have on total demand. They state that the level of exports to Europe will be affected by the timing and volume of new import projects delivering gas to the UK. The base case for their demand forecasts assumes that exports to Europe are lower in the earlier part of the forecast, and then pick up as new supply sources become available to the UK. The forecast of Irish exports is influenced by the timing and volumes of new indigenous supplies to that market.

3.1.3.2 Peak Day Demand

This is forecast to rise at 2.1% per annum over the next ten years. NTS demands are the primary driver for this, particularly the predicted further development of gas-fired power generation. Figure 2 shows peak demand growth compared to historical growth.

Figure 2: Peak Demand Growth compared to Historical Growth



Source: National Grid

3.1.4 NTS – DN Interface

TPA has discussed at length the relationship between NTS and the DN's and it is clear that this is an area that may require further analysis. This was therefore considered as part of the SW Case Study.

Conclusions

General Findings:

National Grid have stated that the process of developing the annual and peak demand forecasts has not changed significantly in the past 5 years. In terms of the methodology for annual demand forecasts, they have developed a hybrid mechanism that utilises different models dependant on what they believe to be the best fit for a particular sector of the market. This is combined with local intelligence relating to large load development in the DN's and information they have gathered from discussions with their own, directly supplied large loads.

There are 5 significant areas of uncertainty in relation to demand:

- Development of the power generation market and gas load factors

[redacted]

- Exports through the interconnector(s) to Europe
- Timing and probability of major reduction of gas exports to Ireland as a result of the Corrib field
- Impact of higher gas prices and increased energy efficiency which reduces household and commercial consumption, possibly delaying the demand led reinforcement in the SW area of the NTS (see section Specific Findings, SW LDZ below).

The seasonal and peak demand forecasting process is closely linked to the processes utilised under the UNC for developing the NDM profiling algorithms and associated load factors. This suggests that there is some form of validation by the industry to factors utilised by National Grid to develop these peak forecasts. The evolution of the NTS/DN contractual and incentive regimes could create a different forecasting environment and also potentially divergent views on DN demand forecasts. The precise mechanism of this and the impact on the NTS 1 in 20 peak day design is unclear at this stage.

This winter we have seen significant levels of demand management, around 40 MCMD in the CCGT sector. National Grid has not proposed to make any adjustment to the 1 in 20 peak day as a result of this, they argue that it is related to short term high prices and does not have a longer term impact. National Grid argues that there is no guarantee that, for example, in 2008/9 all the CCGTs may want to produce electricity on a peak day, and hence this is a reasonable position at this stage, although TPA believes it does have a significant impact in relation to the need for the 5% Flow Margin.

It appears that the use of undiversified demand for the design of the NTS introduces another margin in addition to the Flow Margin and Operating Margins and should be considered at the same time as the review of the Flow Margin.

National Grid has provided TPA with comprehensive presentations on the demand forecasting process at a level of detail that has allowed us to develop an in-depth understanding of their entire methodology.

Our main comment on the general methodology is that it remains essentially an annual process cycle, with no interim updates to cater for sudden shocks, e.g. energy price movements. The FBPQ supply/demand/capex forecasts are based on gas and oil prices in January 2005 which are significantly lower than the broad 2006 consensus. When we asked National Grid to utilise these latest price forecasts for their demand forecasts this would delay the SW demand-led projects by 1 – 2 years compared to the numbers used for the FBPQ. This suggests that there is a risk of inefficiencies in the network development process if account is not taken for shocks (irrespective of the normal cycle), for example building a pipeline for SW demand that may not be required in the proposed timeframe and may not be required at all if demand is reduced and the LNG option becomes the preferred one on the basis of cost.

With respect to the modelling of the interconnector flows to and from Europe, National Grid have presented their methodology, which focuses on there being a notional price differential between NBP and European prices that generates a profile of flows throughout the year, for each year of the plan. These are created under the three scenarios and prices used are linked to energy futures prices. A proxy for European prices is created by a lagged linkage to oil prices. The flows created for each scenario are then interpolated to create a base case interconnector flow for the annual demand forecasting process.

In addition, National Grid assumes the same flows from the UKCS, irrespective of prices and irrespective of utilisation of Rough, Rough prices and the UK-European gas price relationship. There is also no significant change in Rough utilisation in 2 of the 3 scenarios.

As part of the process, gas prices have to be adjusted under certain circumstances to prevent discrepancies between the prices used for this purpose and the prices generated by National Grid for general demand forecasting purposes. National Grid have limited access to any commercial information on the European market and have to resort to assumption/speculation on cause and effect based on knowledge of what happens in the UK and general trading knowledge.

Specific Findings

SW LDZ

This LDZ was reviewed at a workshop on the 7th March as a test case to understand the detailed development of the demand forecasts. There is substantial identifiable demand lead investment associated with this LDZ as the investment is not masked by entry reinforcement projects.

Key issues that we believe need to be understood by examining this specific LDZ are:

- Capacity benefit from higher CV gas: it is believed that this part of the network will receive higher CV gas than it would historically as a result of the Milford Haven and Isle of Grain facilities. This higher CV gas could lead to lower volumes being transported for the same energy demand. [redacted]
- Average consumption for households: as a result of a step change in efficiency legislation in building regulations (condensing boilers mandatory from 1 April 2005) there will be a significant impact on the average annual consumption of households with resultant reduction in peak. Given that the majority of growth in SW is believed to be due to new domestic gas consumers, this is a material factor, together with the increase in non gas heated homes as a result of the new building regulations.
- Impact of higher energy prices: National Grid capex forecasts are based on a January 2005 view of oil at $35/bbl oil which seems no longer to represent the consensus view. The issues to be addressed are whether National Grid forecasts are based on sustainable price assumptions and the way that National Grid take account of shifting assumptions in their investment planning process, particularly ones that appear to represent material changes (eg a new pipeline from Wormington to Sapperton was approved in Q3 2005; will this now be delayed at the end of the Conceptual Design stage?)
- Impact of significantly higher NTS pressures in the southern parts of the NTS [redacted]
- Load management: analysis of recent experience of cold weather provided by National Grid and information from the market suggests that gas demand in winter is significantly affected by short term gas prices. National Grid makes no adjustment to their 1 in 20 peak day based on this evidence. This may be appropriate given the impending assumed supply surpluses; however it does require further assessment in the light of National Grid's relatively low gas price assumptions. It also means that this impact can be taken into account in any review of Flow Margins
- [redacted].

The forecasts of 1 in 20 peak days assume that the load factors within each market sector (with the exception of specific large loads) remain constant over the forecast period. There is currently no evidence of any movement in load factors and so this assumption is a reasonable one. Future forecasts should continue to keep this assumption under review, particularly with regard to any impact on peak demands of load management and, in the domestic sector, the impact on consumption patterns of the increasing numbers of condensing boilers. On this latter point NG will need to ensure that the sample consumption data which they collect as a basis for their analysis properly represents the proportion of condensing boilers in the population at large.

Power Generation

Phasing of power generation build up – certain projects with specific start dates later in the ten year plan may be built earlier than anticipated as a result of different forecasts of the spark spread. Again this is dependant on the energy price forecast assumptions – National Grid's forecast may be out of line with 2006 forecasts. TPA propose some alternative assumptions on power generation growth in section 4.5.1. There is evidence of new coal-fired technology being utilised, which reduces CO_2 emissions and also injection of CO_2 into offshore oil fields as part of an enhanced oil recovery process to avoid emissions. This may have an impact on long term CCGT development plans, however TPA have not made any allowance for this in the forecasts provided in section 4.5.1.

NTS/DN interface

The current forecasting process is in transition with effectively NTS and the DN's having joint accountability for developing DN forecasts. It is important that the impact this has on the NTS DN demand forecasts is understood. It is also necessary to establish how long the transition period will be, to assess the likelihood of ongoing costs in both business areas.

It is unclear at this stage how National Grid is interpreting its current and future contractual obligations to the DN's and how this will evolve as the new contractual relationship develops.

The NTS is gaining a significant amount of linepack as a result of investment in new pipelines, decline in flows from Barrow, Teesside and St Fergus and higher pressures in the southern parts of the NTS. It is important to understand how this 'linepack windfall' is being shared out.

3.2 Supply Forecasts 2005/6 to 2011/12

3.2.1 Methodology

Traditionally National Grid's supply-side analysis was dominated by developments in the United Kingdom Continental Shelf (UKCS) and, therefore the assessment of capacity requirements by terminal depended on accurate forecasts of UKCS field production. With the recent accelerated decline in UKCS production they have adapted their analysis to cater for the increasing reliance that the UK will have on imported gas. Over the past three years their planning focus has changed to reflect the increasing certainty of landing locations for new imports. However National Grid still consider that high levels of uncertainty still exist in terms of forecasting future supplies due to potential import volumes far exceeding demand and the increased development of international gas markets through increased interconnectivity and notably LNG trade.

To reflect these new areas of uncertainty that arise from the shift to import dependency, National Grid have constructed three supply scenarios with which to analyse the supply position in the coming ten-year period, each of which are summarised in this report in section 3.2.3.

The scenarios presented by National Grid in their FBPQ indicate the likelihood of a significant supply surplus in the medium term, if all the various importation projects deliver as planned. They also state that these scenarios recognise that the UK supply market will increasingly be influenced by the world gas market, as supplies imported to LNG facilities or through interconnectors have a number of alternative markets into which they could be sold. For example, National Grid state that the importation of LNG to the UK, and the price of that gas, will be highly dependent on movements in the US and European markets, as the LNG can just as easily be exported from source into those markets. The UK market, therefore, will no longer simply be a function of the balance of UK supply and demand. The supply scenarios, therefore are intended to cover the potential variability of supplies given the influence of these world markets.

National Grid assume that due to the relative stability in terms of their forecast for the decline in future UKCS supplies, compared to the uncertainty over potential import source volumes, that the three supply scenarios are based on a consistent level of supplies from the UKCS with changeable imports.

3.2.2 Forecast Assumptions

The following assumptions are made by National Grid when developing their supply forecasts.

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Source: National Grid

[redacted]

[redacted]

[redacted]

[redacted]

3.2.3 Supply Scenarios

National Grid believes that it remains unrealistic to expect that all of the proposed import projects will meet their proposed development timescales and delivery volumes. In order to manage the uncertainty surrounding these developments, they have developed three supply scenarios. These scenarios intended to be diverse in nature in order to allow a broad range of potential NTS investment requirements to be identified and assessed.

All of the supply scenarios assume a similar profile for UKCS supplies on the basis that the majority of UKCS supplies are currently in production or are planned for development utilising existing offshore infrastructure. Rough is assumed to flow at maximum rate in all but the Auction+ scenario. The supply scenarios build on National Grid UKCS forecasts by adding imports to meet UK demand plus demand that potentially arises through exports to the Continent, and are described briefly below.

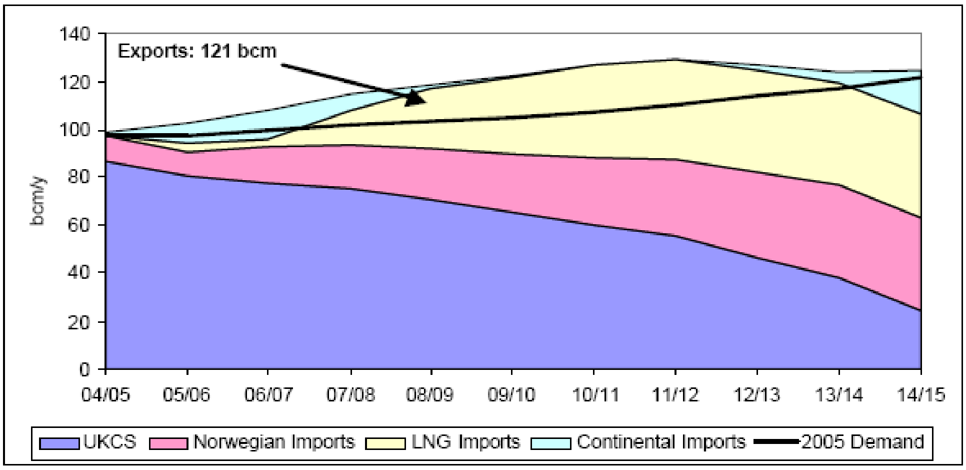
a) 'Transit UK'

In this scenario, the UK effectively becomes a "hub" for European LNG imports and imports from Norwegian gas fields, with gas coming into the various LNG facilities being developed and the Langeled interconnector, and being exported on to Continental Europe. The main features of this scenario are as follows:

- an aggressive, though phased, build-up of imports from Norway and from LNG;
- an appreciable level of exports to the Continent due to the relatively high level of supply, primarily during the summer and shoulder months, increasing NTS throughput significantly. Whilst the Interconnectors are assumed to export for much of the year, their operation is also seasonal with winter imports; and
- due to the surplus of supply in this scenario, some of the proposed UK storage developments are deferred towards the end of the ten-year planning period.

The difference between the aggregated supplies and UK demand results in exports of over 17 bcm in 2010/11, and total export of 121 bcm over the ten year period. This scenario results in high flows into Milford Haven, Grain, and Easington, with high flows out of Bacton.

Figure 4: Transit UK Supply Scenario



Source National Grid

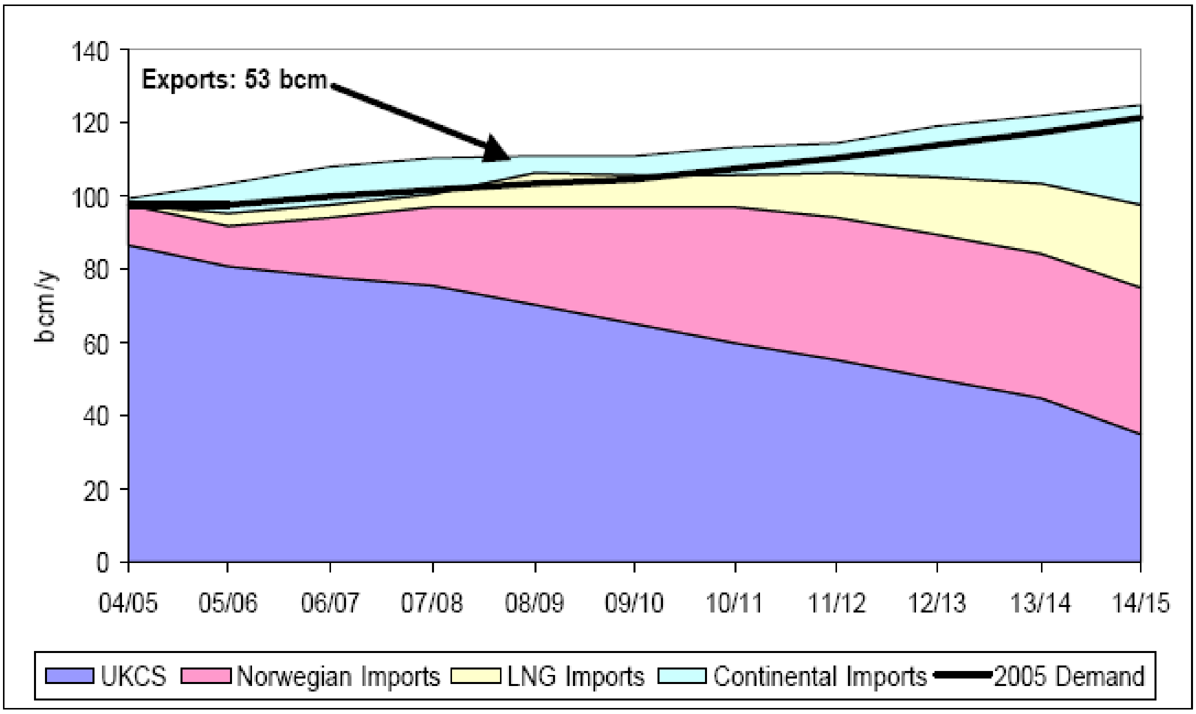
b) 'Global LNG'

In this scenario, LNG is shipped to other markets, and the UK is dependent on imports from Norway and Continental Europe. The main features of this scenario are as follows:

- The majority of LNG potentially destined for the UK is shipped to alternative markets as a consequence of higher prices.
- To meet the supply shortfall, the UK receives relatively high volumes from Norway and, to a lesser extent, from the Continent, where the Interconnectors are assumed to operate on a seasonal basis, with imports exceeding exports from around 2009/10.
- Towards the end of the ten-year planning period, the UK requires additional supplies, which are assumed to be sourced from a combination of LNG and further UKCS supplies.
- With only a short-term surplus of supply, it is assumed that most of the proposed UK storage developments proceed as planned.

In this scenario, with a considerably lower surplus of gas than the Transit UK scenario, exports to the Continent peak at 7 bcm in 2007/08, and total 53 bcm across the ten year period. This scenario results in high flows into the network at Easington and Bacton, with relatively low flows from Milford Haven and Grain.

Figure5: Global LNG Scenario



Source: National Grid

c) 'Auctions+'

The main features of this scenario are as follows:

- The level of required entry capacity is that which has been signalled to National Grid by the market. The LTSEC auction results have been used as a guide in projecting the supply profile across the entry points, with individual terminal and storage flows constrained by the respective obligated capacity levels where necessary.

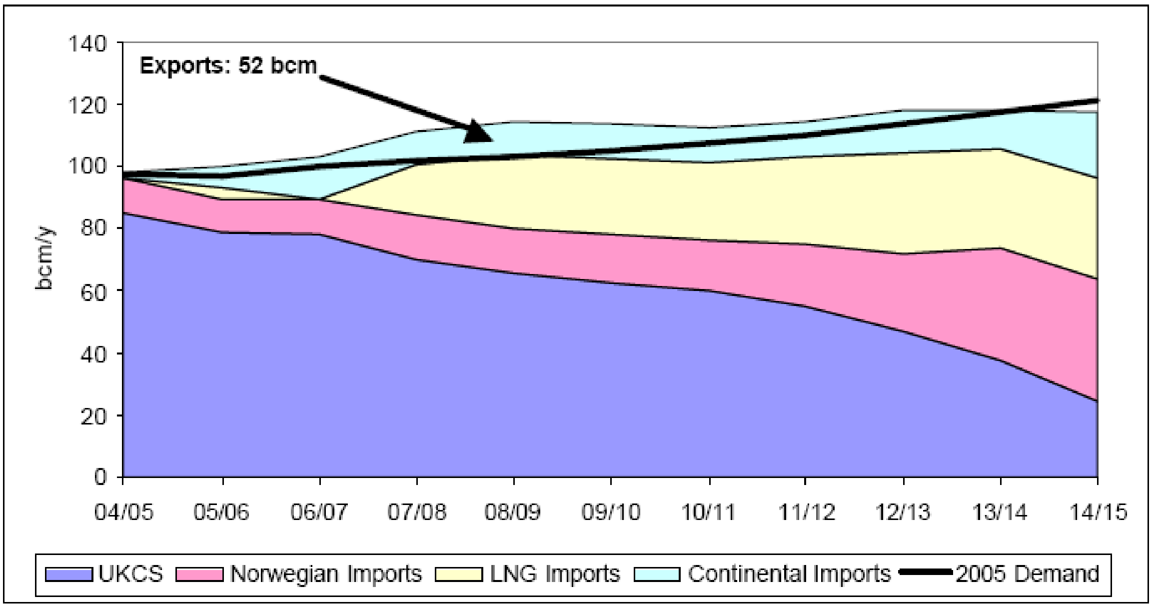
This scenario is characterised by modest levels of continental imports at Bacton in the short to medium term, a significant build up in Norwegian imports at Easington from 2006/07 and very high imports of LNG through Milford Haven from 2007/08. Despite the (auction-driven) limits applied to terminal flows, there is still sufficient supply availability to meet demand until the final year of the period.

Since this scenario is driven by LTSEC auction results, Garton and Barton Stacey are included, in addition to the existing storage facilities.

Despite the (auction-driven) limits applied to terminal flows, there is still sufficient supply availability to meet demand until the final year of the period, with some surplus over the Price Control period. Exports to the Continent peak at over 10 bcm in 2008/09, and total 52 bcm across the ten year period.

Effectively, in this scenario, the level of required entry capacity is set at the baseline levels as set out in the National Grid licence. This scenario, therefore, identifies where further auction signals are required to release capacity through potentially additional network investment.

Figure 6: Auctions + Scenario



Source: National Grid

Conclusions

General Findings:

As with the demand forecasting process the methodology has remained broadly the same for many years, but there have been significant changes in the scope of activities carried out to develop a supply forecast. The UKCS forecasting process is based on gathering intelligence from the producers and supplementing this with other sources of data. In principle this is a reasonable approach to developing a view of potential annual gas supply availability. However, TPA believes that this approach may not capture the changes in output and seasonality from the UKCS as a result of a number of factors:

- Potential over-supply forecast in the period 2007 – 2010 at a time when LNG re-gasification facilities in the US are still limited and cannot accommodate all the new LNG production from the Atlantic Basin and the Middle East
- With gas and gas/condensate (with around 70-80% of revenue from gas, 20-30% from condensate) fields in decline, if gas is not produced in the period April – October, it can be produced in the following higher priced winter period. When fields such as Armada and Britannia were on plateau in the 1998 – 2004 period this was not the case.
- Recent increases in taxation can be expected to delay some further investment (Shell announced a reduction in drilling) which may tend to reduce UKCS flows in the short term, though the gas will be developed later.
- Trend of divestments of fields by the majors to smaller companies (eg Tullow) who may have a value approach to production rather than a focus on maintaining production volumes whatever the gas price.

National Grid has not used different UKCS scenarios when they have developed alternative scenarios for the new imports. We have presented in this report an alternative scenario that postulates a certain greater seasonality from the UKCS fields once the short term high gas prices have ended, that have the capability and commercial incentive to do so (see section 4.4).

Another critical element of the supply assumptions relates to the LNG import facilities. A number of important issues arise from the sourcing of LNG and the profiling of flows from the new terminals. As a general point, National Grid treats all LNG terminals in the same way. This may not be appropriate, given the different contractual relationships and supply sourcing options at each terminal. TPA believes that it would be useful if National Grid developed a model to establish the relative pecking order of the LNG imports, Norway, UKCS, Interconnector(s) imports and Rough utilisation. This model could also take into account the US-European dimension.

National Grid have provided comprehensive presentations to TPA on the supply forecasting area, allowing a thorough analysis of the methodology and results which has yet to be carried out. We believe that a more practical approach to the development of supply scenarios would be to assess the impact on the network of a matrix of supply options for imports and analysing the impact on investment of these combinations, for example, is it commercially feasible for concurrent high flows from Milford Haven and Ormen Lange and if so, what is the impact on NTS design. This may provide a more realistic and sustainable range of options. This approach will be dependent on future evolutions of the entry capacity incentive regime, but in light of the fact that specific commitments have been made by the buyers of entry capacity there will be some clear signals as to the future requirements for capacity at these points.

In relation to Milford Haven entry capacity, National Grid is carrying out around £800M of reinforcement in 2 phases. The first phase extends the NTS to Milford Haven, the second phase expands the capacity of the NTS with a new 48" pipeline across part of the Brecon Beacons National Park. An important issue to be determined is the reasons for the current position whereby National Grid is incurring significant capex increases in order to complete both these phases in time for the capacity to be made available.

Specific Comments:

The focus with respect to the supply forecasts is to establish how supply behaviour will change when there is the potential for large surpluses and uncertainty as to actual flows from a number of key sources. National Grid has developed three scenarios and has stated that their investment plans cover all these scenarios. However there are scenarios that have not been considered that may be material to long term investment plans. The most significant alternative is to vary UKCS behaviour when LNG imports are significant. National Grid in all three supply scenarios assumes the same seasonal supply profile for the UKCS. An alternative is to assume a different seasonal supply profile with the UKCS operating on a reduced load factor in summer. This is dependent on assessing a number of other factors.

- Extent of UKCS production associated with oil production: National Grid believe that this is high, but we believe that the amount of gas directly associated with oil (as opposed to condensate where around 7% of income comes from gas) is relatively limited and not a dominant driver in the UKCS as a whole.
- LNG world market winter and summer sales patterns: is it possible to assume that summer supplies can be sustained in the UK from LNG, which will in turn have an impact on the Milford Haven and Isle of Grain seasonal profiles. (TPA believes it may not be possible for all summer LNG to go the US because of limitations on regasification capacity in the US.)
- Impact of Ormen Lange and BBL load factors and seasonal profiles
- Probability of further Norwegian supplies at St Fergus

This work also has an impact on the assessment of demand related investment for new power stations [redacted] as the National Grid assumptions are that flow into the network from these terminals cannot be assumed throughout the year.

Supply Demand Match and Network Analysis:

National Grid present three supply scenarios which generate three different interconnector flow assumptions, but only one gas price assumption. However the three interconnector assumptions create three different sets of UK market prices.

The ability of the US market to accommodate LNG destined for the UK is crucial to assumptions regarding the operation of the UK import facilities and hence the supply demand match.

5% Flow margin: there has been no change to the level of this margin since its introduction and reduction will lead to capacity benefits and possible reduction in capex.

The need for this level of margin was raised in the draft HBPQ comments. There is the potential to revisit this in the light of recent developments on the network.

- Greater network flexibility
- Additional capacity (via electric compressors)
- Evidence of demand side response.
- Improved information availability (iGMS)

Consideration should be given to tailoring the flow margin on a geographical basis. [redacted]

SECTION 4. ALTERNATIVE FORECASTS

4.1 Introduction

TPA Solutions have purchased a set of supply and demand forecasts from the Energy Contract Company who has been publishing forecasts for several years. These forecasts are summarised below. TPA Solutions have also produced their own forecasts, based on different sources of data and their own assumptions. These are provided in this section together with a comparison with the ECC data and National Grid.

4.2 Energy Contract Company Forecasts

The high level conclusions from the ECC forecasts are as follows:-

1. The period of explosive growth in gas demand in the UK in the nineties now seems far behind us. However, despite a period of static performance in the first few years of this decade, the UK gas market seems set for a period of modest growth. From 2003/04 to 2013/14, gas sales to Power Generation should grow from 3000 to almost 4000 mcfd. However, gas use in generation is expected to dip a little in 2005/06 and 2006/07. All of this growth will come from 2007/08 onwards. This is equivalent to an annual growth in demand of 3% per annum from 2003/04 to 2013/14. The increase in sales in the "Other" markets, (Commercial, Industrial and Domestic, will be a little more modest but still positive.) Sales in this sector are forecast to increase at around 2% per annum up to 2013/14.

2. The position on gas demand is one of modest change but on the supply side there will be a major shift in the landscape. In 2003/04 the UK had net imports of close to zero. However, we have now become a modest net importer of gas, and the import percentage should rise steadily over time reaching around 45% in 2010/11 and just over 60% in 2013/14.

3. Over the next few years we expect to see a switch back series of changes in the overall balance of supply and demand on a yearly basis in the UK. For the next 12 to 18 months the market should remain fairly tight, but things might ease a little in 2006/07 when the final phase of the Interconnector expansion comes on stream on stream. From 2007/08 onwards, there should be a short period of massive oversupply in the UK market. This will be particularly noticeable in 2007/08 and 2008/09, and to a lesser extent 2009/10. It is worth pointing out that our forecasts still show a substantial supply overhang in the latter part of this decade despite an assumption that LNG imports are reduced very significantly in the final three years of the decade. There now seems to be a fairly high degree of certainty about the oversupply in the medium term.

4. The figures set out in the table below show a substantial over-supply of gas for 3 years starting in 2007/08. However, these figures are based solely from import projects and known UKCS fields. A number of other import projects have also been proposed, and these seem likely to go ahead in the near future. If this was to be the case, then the period of over-supply could be for 4-5 years, rather than just 3 years.

5. In the last year or so, the high prices seem to have had a very marked effect on some sections of demand. In the winter of 2005/6, some major chemical companies have either shut down their plants completely or switched to oil. Our assumption is that once prices fall in a couple of years time, this load will be restored. Perhaps more significantly, there appears to have been major fuel switching by Power Generators who have shut down gas fired plants and started running coal fired plants instead.

6. Clearly, this fuel switching is a product of high spot prices and will probably occur again in the winter of 2006/07, but should disappear thereafter. The key question is that when the market starts to recover and prices increase again at the end of the decade, will this phenomenon reoccur at times of high spot prices? Our view is that it will occur to a noticeably lesser extent as Power Generators will be much more constrained in their behaviour in the longer term. The ability to turn up coal-fired plants in the future and sell gas on the spot market will be significantly less than it is now.

   - From 2008 onwards, the EU Large Combustion Plant Directive will restrict the use of coal fired plants that are not filled with FGD. Effectively, these plants can only average 28%% load factor from 2008 to 2015.
   - Emission Trading Limits will enter Phase 2 from 2008 which is more restrictive than the current Phase 1. This again will inhibit use of coal fired plants.
   - The average age of coal fired plants in the UK are already 30 years. By 2013, it will be almost 40. It is questionable how reliable plants of this age will be. Most plants were built originally for a life of around 30 years.

7. The position on winter supply and demand is a little less favourable than for the annual gas balance. The supply demand balance for the 2006/07 winter is very much weather dependent. If the winters continue as they have for the last fifteen years, 1-2^{o}C warmer than average then there should be few, if any supply problems. If it is seasonal normal or even mildly cold then the gas market may experience some modest tightness and Month Ahead prices could well be in the 80-100p range for significant parts of the winter. However, if we have a full blown 1 in 50 winter then the supply position looks rather marginal. The prospect of cut backs in supply to firm customers is fairly limited, but we could have a prolonged period with spot prices at extraordinarily high levels, perhaps as much as £5/them.

8. By 2007/08 and 2008/09, the massive oversupply should eliminate any problems even in 1 in 50 winter conditions. However, thereafter the position deteriorates quite quickly. In the absence of new gas storage facilities (or some comparable measure affecting gas demand) by 2012/13 the risk of cutbacks in gas demand and consequent power cuts is probably slightly worse than it was for 2005/06.

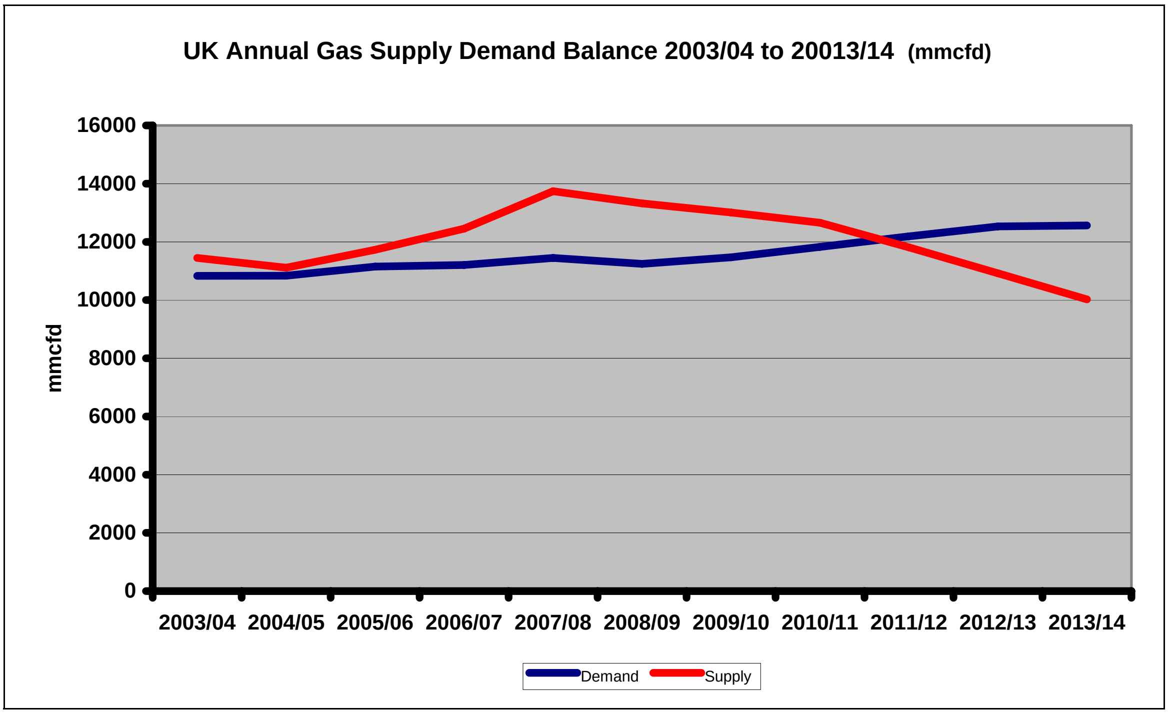
The supply demand match produced by ECC is reproduced below in tabular and graphical form. Note the units are all in mmcfd.

Supply Demand Match produced by ECC (mmcfd)

YEAR	POWERGEN	OTHER	DEMAND* UK only	EXPORTS	TOTAL	SUPPLY	SURPLUS/ (DEFICIT)
2003/04	2975	6446	9421	1410	10831	11445	614
2004/05	2952	6427	9380	1455	10835	11114	279
2005/06	2800	6798	9598	1461	11059	11726	667
2006/07	2792	6968	9760	1355	11115	12542	1427
2007/08	3209	7149	10358	1067	11425	13741	2316
2008/09	3135	7283	10419	709	11128	13324	2197
2009/10	3281	7419	10700	714	11414	13009	1596
2010/11	3451	7543	10994	760	11754	12657	903
2011/12	3593	7680	11273	790	12063	11808	-255
2012/13	3780	7784	11564	850	12414	10918	-1496
2013/14	3928	7899	11827	714	12541	10024	-2516

Source: Energy Contract Company

Figure7



Source: Energy Contract Company

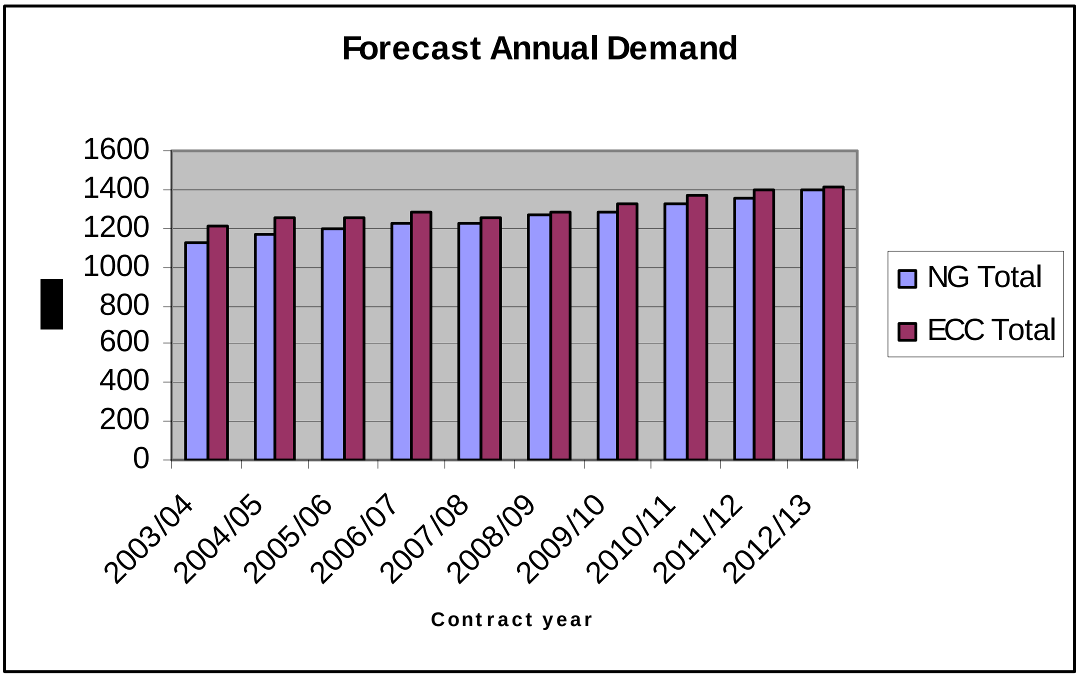
4.3 Comparison with National Grid Demand Forecasts

As a general observation there is considerable difference of opinion between ECC and National Grid on the duration of the supply surplus, with ECC showing a deficit returning in 2011/12, where National Grid sees no deficit under two scenarios up to and including 2014/15 and in one scenario a deficit appears after 2013/14. The extent of supply surplus at its greatest in 2007/8 (for ECC) is 20%, whereas National Grid has a figure of up to 65%.

A direct comparison of the figures shows up some anomalies as the data is not on the same basis. The National Grid annual demand data as presented in the 10YS is for NTS throughput, whereas the ECC data is total UK demand, so there will be differences shown. However when looking at a UK supply demand match the data is comparable.

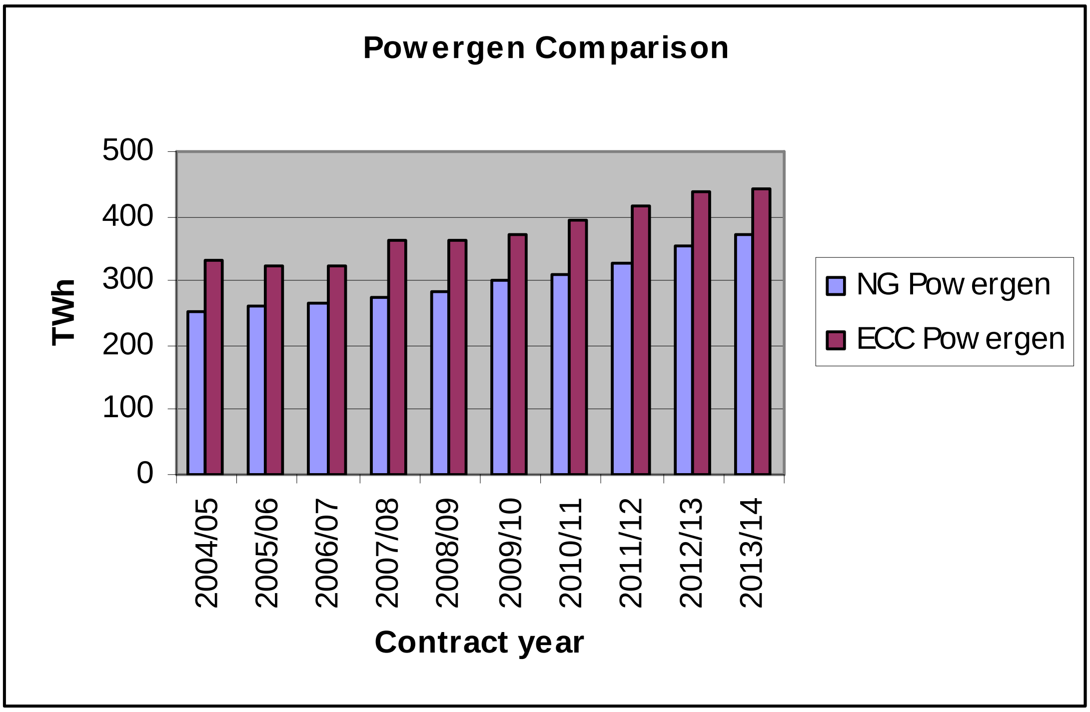
The following graphs illustrate where the differences in assumptions occur.

Figure 8



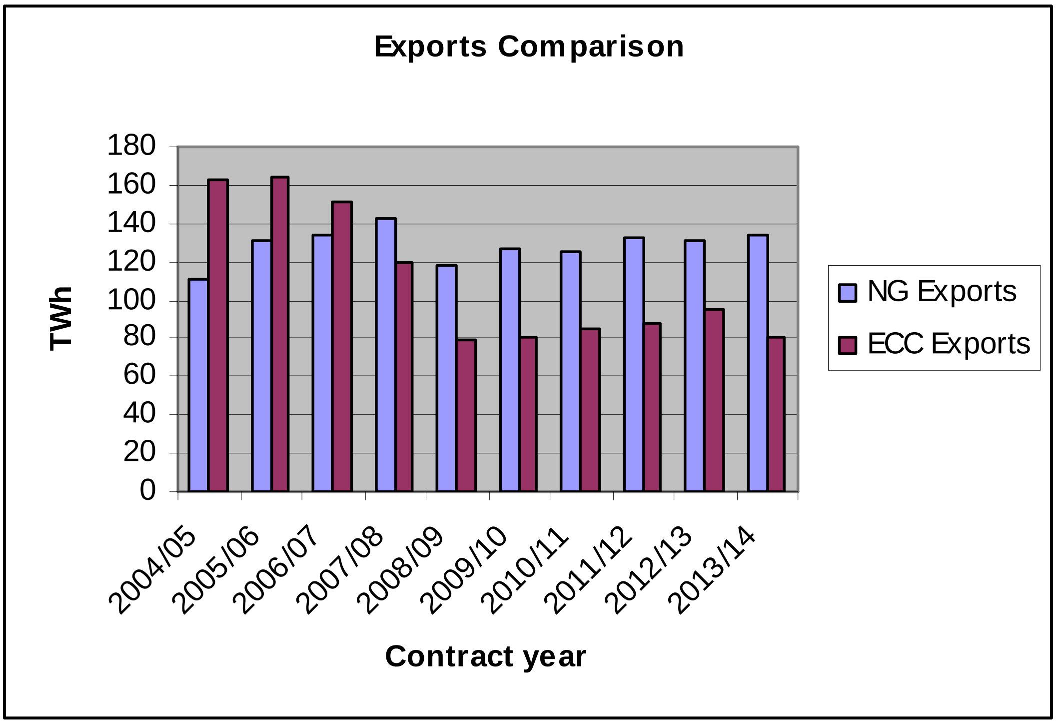
Source: TPA Analysis

Figure 9



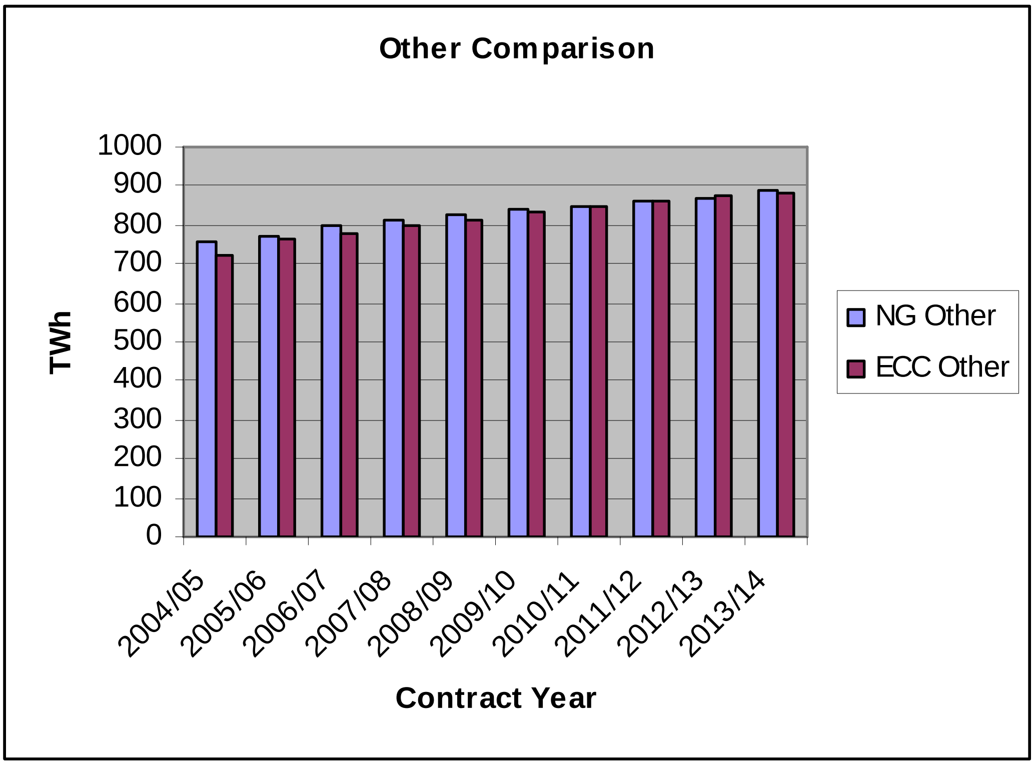
Source: TPA Analysis

Figure 10



Source: TPA Analysis

Figure 11



Source: TPA Analysis

The most notable variances are as follows:

- The other category should be identical given that the ECC figures use the National Grid data. However there may be some conversion differences as the data presented by ECC was in mmcfd compared to TWh by National Grid and the annual data for each sector is presented in calendar years rather than contract years for the ECC data.
- Powergen assumptions are significantly higher for the ECC data, but this is attributable to the fact that the NG figures used for the comparison do not include forecasts of power generation capacity that is outside the NTS.
- The biggest variation can be seen in the export assumptions, which are primarily a result of the different methodologies used by the two different forecasters. National Grid essentially determine this by developing three forecasts linked to their three supply scenarios and then taking figures for exports that represent a reasonable average from the three scenarios. ECC forecasts reflect the contracts that are in place for export through the Interconnector.

Peak demands are not reproduced by ECC except on a monthly basis through the winter period, meaning it is not possible to derive a meaningful comparison.

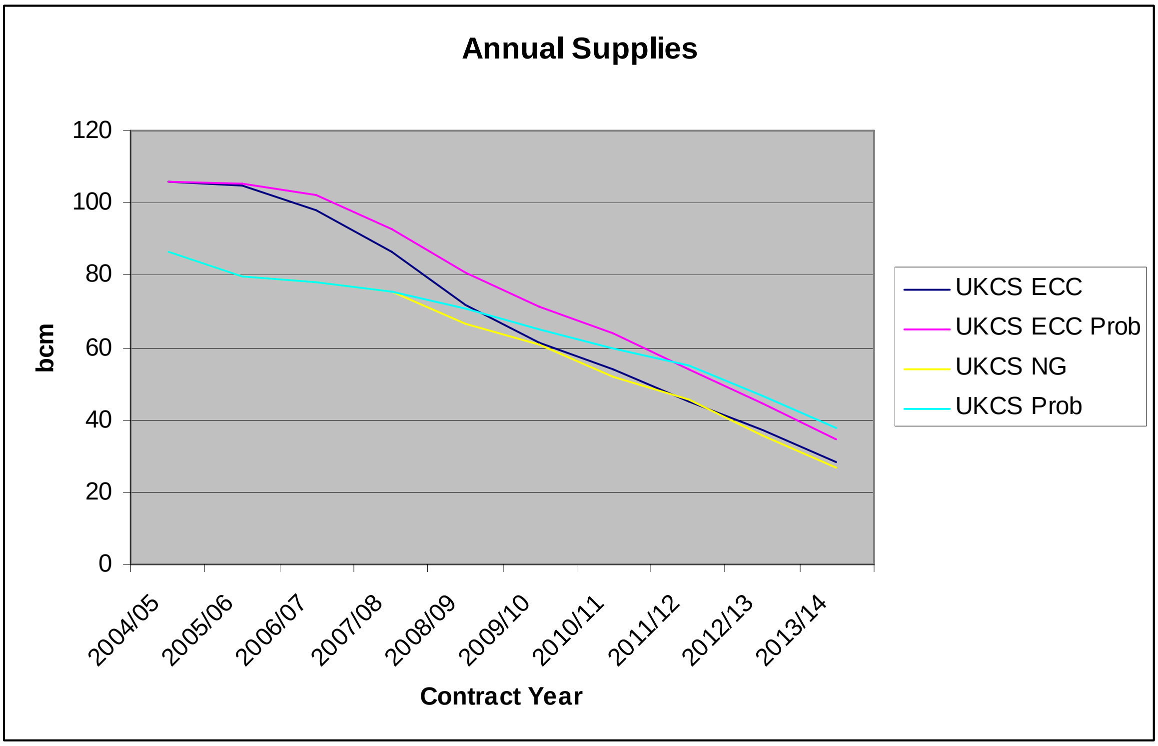
4.4 Comparison with National Grid Supply Forecasts

On the supply side there are two crucial areas to examine, the UKCS assumptions and the level of import capability.

4.4.1 UKCS Comparison

The graph below shows the two different assumptions for UKCS annual deliveries.

Figure 12

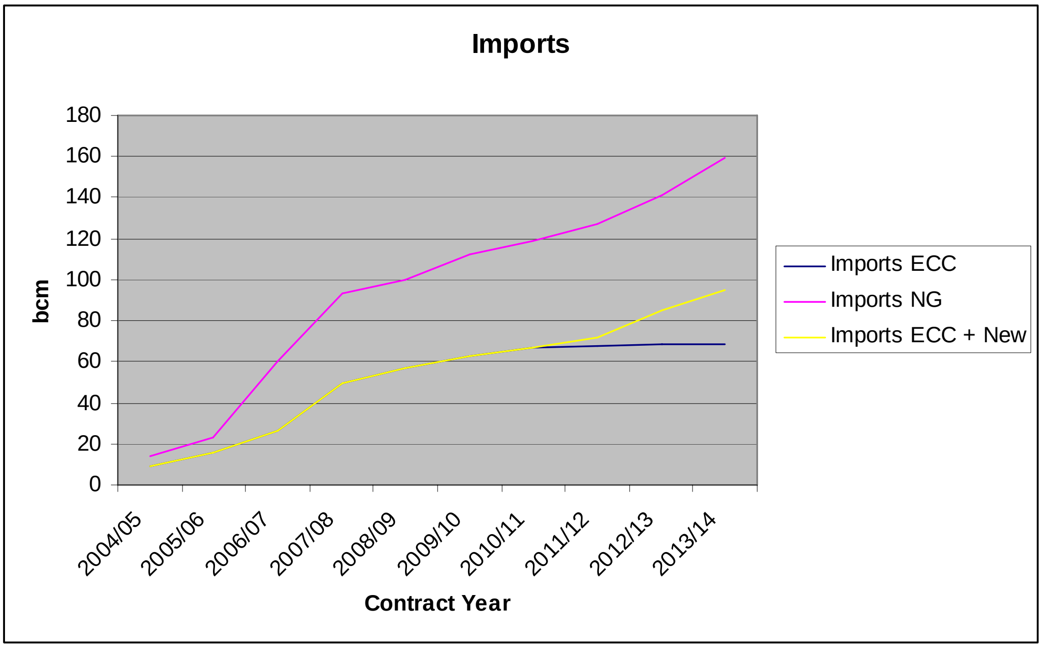


Source: TPA Analysis

There are some substantial differences regarding the forecasts, particularly in the early years. It is assumed that these differences occur because of definitional differences. DTI production data for 2004 is shown as 103 bcm, close to the figures provided by ECC, however the DTI production data includes volumes that are not available for UK consumption and are part of own use gas offshore and other losses and also gas that is directly exported to Europe via offshore connections. Own use alone accounts for 7% of production which would bring the figures closer at the beginning but take the National Grid figures above those of ECC in later years.

4.4.2 Import Assumption Comparison

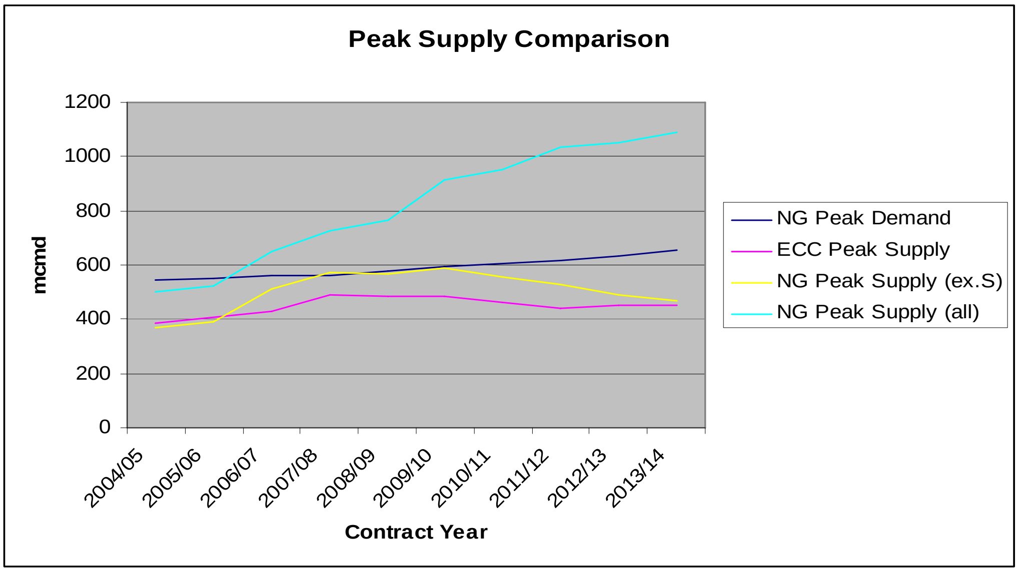
Figure 13



Source: TPA Analysis

There is clearly a very different set of assumptions used in the two forecasts. The National Grid figures reflect maximum potential import capacity, whereas the ECC numbers reflect the fact that they have only included a specific set of projects, but do not categorise their new gas requirements as imports. The graph shows the impact of adding this new gas as all imports.

Figure 14

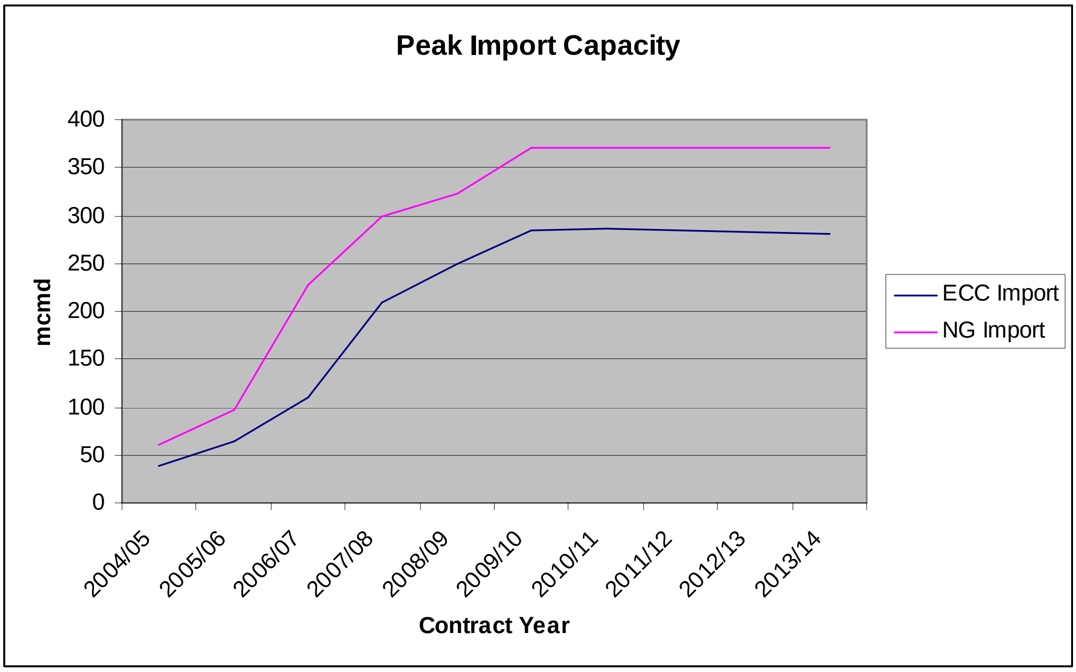


Source: TPA Analysis

The differences between the assumptions shown for peak supply without storage are not attributable to UKCS differences as these are broadly similar, but not identical however. The major difference is in the physical import capacity assumptions. This graph highlights the massive potential over supply of peak if all projects are built that NG have included.

This is illustrated by the graph below, which shows the assumptions made by each forecaster.

Figure 15



Source: TPA Analysis

The major differences between the two forecasts are a lower assumption by ECC for Tampen volumes, [redacted] and slower build up of Langeled and BBL gas.

4.5 TPA Forecasts

TPA having reviewed the forecasts produced by National Grid and ECC has concluded that there are some specific assumptions that TPA will use as the basis for the development of our own forecasts of supply and demand. As a general comment on the overall forecasting process, TPA believe that there are a range of factors that are applicable to the UK market that do not apply to any other markets in the world at this specific moment in time, given the unique combination of the characteristics of its supply system, market arrangements and the political climate.

The impact that gas prices have on the market is proving to be a crucial factor in the development of reliable forecasts of growth in demand and forecasts of future supplies and storage facilities. As highlighted by ECC there is the potential for a cyclical movement in the supply demand balance, which will influence prices in the UK market as supply surpluses build up and decline as the market adjusts to the perceived surplus or deficit. Any sustained downward trend in prices will encourage greater use of gas. However it must also be assumed that despite this possible trend, that there will also be increasing pressure to improve efficiency to reduce greenhouse gas emissions and to increase the proportion of renewable sources.

It is important therefore to focus on those factors that are known in the first instance, rather than the more speculative elements that have been put forward to highlight the level of uncertainty in the market.

4.5.1 Demand

The fundamental assumptions and methodology that National Grid have made with respect to their annual and peak demand forecasts are generally sound, with the exception of the energy price forecasts that they used for developing their growth forecasts. TPA therefore propose to take the LDZ demand forecast provided by National Grid and apply a correction to this forecast based on the preliminary analysis provided by National Grid as to the effect of using the very latest energy prices. These forecasts are provided below.

LDZ Annuals

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
TPA	715	716	711	731	748	767	787	802	824	843
NG	715	734	752	771	783	797	809	823	832	845

LDZ Peaks

	2004/5	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
TPA	4585	4540	4494	4585	4700	4815	4929	4998	5136	5227
NG	4585	4655	4751	4839	4922	5004	5066	5127	5186	5242

Source: National Grid and TPA

NTS forecasts are only marginally changed by TPA on the basis that these are primarily lead by specific power station loads as we do not have any alternative data that reflects different assumptions with two exceptions. Our understanding is that [redacted] and [redacted] may be required earlier than planned by National Grid. We have adjusted the NTS forecasts to reflect this. The latest view on [redacted] is that it will commence deliveries in 2008. This is quite ambiguous as this could mean 1st January 2008 or 1st October 2008, the start of the gas year. The National Grid assumptions are that [redacted] will commence in the winter of 2007/8 which now seems unlikely given the planning difficulties experienced with the pipelines. [redacted]

NTS Annuals (excluding IUK)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
TPA	343	357	363	355	360	376	423	448	466	477
NG	343	357	348	349	360	382	400	429	458	483

NTS Peaks

	2004/5	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
TPA	1300	1307	1328	1386	1362	1434	1589	1674	1732	1826
NG	1300	1307	1328	1260	1350	1435	1480	1560	1679	1826

Source: National Grid and TPA

Comparisons for the total NTS annuals (excluding IUK) and 1 in 20 peak day are as follows:

Total Annuals

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
TPA	1070	1085	1087	1098	1120	1154	1220	1261	1299	1330
NG	1070	1103	1113	1132	1155	1190	1219	1262	1300	1338

Total Peaks

	2004/5	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14
TPA	5885	5846	5821	5971	6062	6249	6518	6672	6868	7053
NG	5885	5961	6079	6099	6272	6439	6547	6688	6865	7068

Source: National Grid and TPA

With respect to the annual demand forecasts they have been adjusted to reflect the revised phasing of LDZ growth, but the biggest issue is the assumptions regarding the development of Interconnector forecasts. National Grid was asked to validate their assessment of Interconnector flows for each scenario and the resultant impact on gas prices. However the response received indicated as expected that different scenarios create different UK price assumptions. These prices are not used to re-assess the UK gas demand. TPA believe that the most effective way of forecasting Interconnector flows is to avoid any assessment of comparative prices as this has many variables that could not be easily factored into a simple model. A more pragmatic approach is to simply assume that total Interconnector flows are governed by the ability of the UK market to provide gas under certain conditions.

There are also many other areas where flexibility can be achieved, for example through the cut back of supplies from imports from Norway or from LNG.

4.5.2 Supply Forecasts

As outlined in the introduction to this section TPA are going to forecast the supply to the UK market based on firm developments to the supply infrastructure. Also with regard to the UKCS TPA will be assuming greater seasonality from the fields that have the scope to deliver gas independently of oil production. The following assumptions will be made regarding the new developments.

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Source: TPA

[redacted]

4.6 Conclusions

The implications of the different forecasts are significant in terms of annual flow profiles from the terminals and through the Interconnector. However the impact on capital investment is minimal as it would be expected that at demand levels within the period 1st November to 31st March in any year, most fields would be expected to be close to maximum delivery levels for most of this period anyway, so the design of the network is unaffected by different supply assumptions. What is more important is how the different supply sources are assumed to interact with each other, where there is a supply surplus. To avoid getting into the different market interactions it would be a simple process to develop a matrix of different supply assumptions, combined with the assumption that the Interconnector can be flexed to provide the balance, as it is the only current dual import/export route. A further sensitivity could be applied whereby some of the import sources could be used as alternative balancing tools, reducing flows through the Langeled or Vesterled pipelines or even reducing outputs from the LNG sites. So for example on the peak day analysis for 2008/9 it could be assumed that all UKCS inputs are at maximum, but the remaining demand can be met by the following different combinations of flow from the import facilities. TPA has suggested some possible combinations in the table below.

TPA Matrix Scenarios – Some Examples

	TPA Match	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Bacton	77.00					
Barrow	22.92					
Easington	11.07					
St Fergus	95.77					
Teesside	24.21					
Theddlethorpe	24.22					
Point of Ayr	1.94					
UKCS	257.14	257.14	257.14	257.14	257.14	237.14
IOG	19.80	19.80	19.80	19.80	15.00	19.80
Langeled	54.80	54.80	54.80	54.80	40.00	54.80
IUK	65.00	65.00	20.00	65.00	65.00	65.00
BBL	41.00	41.00	41.00		20.00	41.00
Milford Haven	44.00	44.00	44.00	44.00	30.00	44.00
Rough	42.00		42.00	42.00	30.00	20.00
MRS	84.30	84.30	84.30	84.30	84.30	84.30
LNG	47.30				20.00	
Total	655.34	566.04	563.04	567.04	561.44	566.04
Demand	558.51	558.51	558.51	558.51	558.51	558.51
Surplus	156.13	7.53	4.53	8.53	2.93	7.53

Source: TPA

National Grid has indicated that they are considering this matrix type approach to their analysis, but have not developed their proposed matrix at this stage. TPA fully support the development of a methodology for scenario analysis that does not rely on assumptions regarding the movement of relative European and World gas prices as there are too many variables and uncertainties and a wide range of opinions on how they interact with the UK market. We would not expect that for the period of this PCR that any additional investment would be required to accommodate the scenarios suggested in the above matrix. However inclusion of new import or storage developments other than those in the matrix may trigger new investment.

SECTION 5. FORECAST CAPEX

5.1 Introduction and Methodology

There are 3 periods that are subject to review by technical Ofgem consultants:

i) 2002/3 – 2004/5 (reviewed by TPA in a separate Review of Historic Opex and Capex)

ii) 2005/6 – 2006/7 – last 2 years of current PCR period

iii) 2007/8 – 2011/12 – full 5 years of next PCR period

This report reviews the 7 years from 2005/6 to 2011/12, following the same basic methodology as the historic review, with the 2 periods identified separately given the different regulatory allowance periods.

This report follows the same basic methodology as the review of the capex programme completed in the period 2002/3 to 2004/5, with TPA asking two main questions:

- What is the Business Case for the investment?
- Are there any projects that should not be supported or that may reasonably be delayed?
- Are there any recommendations related to regime design that influence the size of the capex programme ?

- Is the delivery of the investment efficient and are the estimates for the costs of delivery of the capital programme reasonable?
- Are there any recommendations related to project delivery ?

This review is set out as follows:

Section 5.1 is an Introduction

Section 5.2 sets out the total level of capex proposed by National Grid in the 7 year period in its FBPQ response

Section 5.3 sets out National Grid's detailed Capex Plan

Section 5.4 sets out TPA's focus areas for the review based on its analysis of the historic capex and from an initial review of the National Grid capex plan

Section 5.5 sets out TPA's review of the business case for load related capex with investment to increase baselines identified separately

Section 5.6 sets out TPA's review of the business case for non-load related capex

Section 5.7 sets out TPA's view of the efficient costs for the delivery of the programme set out in 5.5 and 5.6

Section 5.8 sets out TPA's Executive Summary and a view of the appropriate level of allowable capex for the periods 2005/6 – 2006/7 and for 2007/8 – 2011/12

5.2 Proposed Capex

National Grid's capex is driven by both the external driver of changes in the supply and demand markets, known as load-related expenditure, and by the need to comply with environmental and safety legislation and replace assets, known as non load-related expenditure.

National Grid's Base Case forecast expenditure for the last 2 years of the present PCR period and for the full 5 years of the next PCR is shown below:

National Grid Forecast Expenditure

	Category	First 3 years of current PCR	Last 2 years of current PCR		Full 5 years of next PCR					
		02/03 – 04/05	05/06 - 06/07		07/08	08/09	09/10	10/11	11/12	Total
Load Related	**Entry – Capacity**	161	538		329.9	144.4	21.8	5.6	0.4	502.1
	Entry – Summer Flex	78.7	2.9		0.0	0.0	0.0	0.0	0.0	0.0
	Exit – power generation	0.5	27.4		48.6	78	57.7	29.3	36.7	250.3
	Exit – load growth	61.6	5.4		15.3	28.4	27.5	38.3	30.0	139.6
Non Load-related	**Compressor Emissions**	0	69.5		68.8	46.5	28.6	19.7	19.7	183.3
	Comp and terminal repex	46.9	25.4		24.6	23.9	26.3	22.5	22.5	119.7
	Other Major Infrastructure	0	0		23.1	9.4	16.3	3.3	0.5	62.6
	Other NLR Capex	9.7	23.2		18.6	20.3	12.9	10	11.2	73
	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Total	358.4	573.7		533.6	360	207	144.2	136.7	1381.5

Source: National Grid HBPQ, TP1135 and FBPQ Data

[redacted]

NB: All costs are presented in 2004/05 prices. For approved projects, National Grid have indicated that project costs are turning out to be significantly higher than in the FBPQ as projects move beyond the design stage into construction. The project costs in this review are the FBPQ costs, the increased costs are discussed in Section 5.7

National Grid provided updates to the 05/06 figures (i.e. actual figures) in September 2006. The most material items in these updates were increases (relative to the original submission) of £4.4M in the costs for South West Reinforcement and £18.1M for the Felindre to Tirley pipeline. Other minor adjustments relative to the original submission were made including an overall £3.6M decrease in costs of compressor projects, and a decrease of some £4m for the other capital project costs. These figures have not been updated in this report, because TPA has not received revised forecast figures for 06/07. [redacted]

TPA's categorization of non load related costs is as follows:

- IPPC – specifically related to NOX and the cost of fuel gas metering required as a result of the Emissions Trading Scheme
- Compressor and terminal replacement - mainly compressor station related assets but certain assets at terminals also
- Other Major Infrastructure – [redacted]
- Other Non Load Related Capex – everything else that is not in the above categories including such things as entry gas metering and cab ventilation

[redacted]

- Note - capital funded by customers (related to infrastructure at entry or exit) at a level of **£9.1M** is forecast in the period 2005/6 – 2006/7 and a further **£5.1M** is forecast to be required in the forthcoming Price Control period. This is excluded from the above figures.

SO capex has not been included in this review.

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5.3 National Grid's Capex Plan

The following section is a summary of National Grid's Capex Plan.

5.3.1 Load related expenditure

5.3.1.1 Entry related

Total entry capacity expenditure of £538M is forecast in the period 2005/6 – 2006/7 and a further £502.1M is forecast to be required in the forthcoming Price Control period.

The entry capex falls in three categories:

a) Approved and under construction (forecast £560.1M in 05/6 – 06/7 and £511.8M in next PCR period)

The majority of entry capacity related capital expenditure in the forthcoming Price Control period is already under construction, validated through the LTSEC auction process, together with the known additional volumes of gas from Ormen Lange landing at Easington in 2007. As such the majority of the entry capacity expansion work is already underway:

- Easington (to meet existing baselines) [redacted]
- Isle of Grain – increased capacity at an existing System Entry Point
- Milford Haven – new System Entry Point
- Bacton (to deliver baseline capacity as a result of the capacity expansion at the Isle of Grain)

Over 90% of the total submitted entry expenditure falls into this category.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

5.3.1.2 Exit Related

Total exit capacity expenditure of £32.8M is forecast in the period 2005/6 – 2006/7 and a further £431.3M is forecast to be required in the forthcoming Price Control period (includes EC Harris unit cost increases).

The exit capex falls into two categories:

a) SW LDZ demand

The only capex proposed in the next 7 years related to any DN load growth is in relation to the SW LDZ (part of Wales and West DN) to meet 1 in 20 obligations. The total programme is £142.2M (forecast £5.4M in 05/6 – 06/7 and £139.6M in next PCR period) with the first part of the programme underway.

- Wormington to Sapperton is approved and underway - £42.5M (£2.6M and £39.9 in the 2 periods)
- Forecast - £99.7M

b) Power Generation

There are 3 categories of capex in relation to power station loads:

i) Approved and under construction (forecast £22.5M in 05/6 – 06/7 and £53.8M in next PCR period)

[redacted]

ii) Probable (forecast £4.9M in 05/6 – 06/7 and £39.3M in next PCR period)

[redacted]

iii) Possible (forecast £157.1M in next PCR period)

National Grid have identified two potential developments, [redacted] and [redacted], that may require significant investment to provide firm capacity [redacted]

5.3.1.3 Non load-related expenditure (excluding SO)

Total non load related capex of £123.7M is forecast in the period 2005/6 – 2006/7 and a further £458.1M is forecast to be required in the forthcoming Price Control period:

The non load related capex falls in [redacted] categories:

a) Integrated Pollution Prevention and Control (IPPC) and emissions trading related related investment (forecast £69.5M in 05/6 – 06/7 and £183.3M in next PCR period)

National Grid have negotiated an agreement with the EA and SEPA to invest at those sites causing the highest level of emissions, starting with a first phase of two sites in the current Price Control period, and continuing with a second phase of seven more in the next period. In addition, improved fuel gas metering at compressor stations is required for compliance with the rules of the Emissions Trading Scheme. Investment of **£183.3M** is forecast to be required in the forthcoming Price Control period.

b) Related to replacement of compressor and terminal assets (forecast £25.4M in 05/6 – 06/7 and £119.7M in next PCR period)

National Grid forecasts an increase in the expenditure required for asset replacement (“Serviceability”) driven by asset condition over the forthcoming Price Control period, in 4 categories:

- Protection and control systems (£44.8M)
- Rotating machinery power train (£22.9M)
- Valves and actuators (£17.1M)
- Miscellaneous other plant at terminal and compressors (£34.9M)

Note – replacement of compressor (and terminal) telemetry is discussed in a separate TPA report, SO Capex/Opex

c) Other Major Infrastructure (forecast £0M in 05/6 – 06/7 and £52.7M in next PCR period)

(i) Replacement of the Humber crossing pipeline (£28.6M)

(ii) Glenmavis LNG (forecast £0M in 05/6 – 06/7 and £24.1M in next PCR period)

Whilst part of National Grid’s business which is currently outside RPI-X regulation, the investment at Glenmavis is required as part of National Grid’s safety case.

d) Other Non Load Related Capex

Anything not covered above including:

- Gas quality metering at entry
- Liquid monitoring at entry
- Gas generator 'hot washing' and air intake anti-icing
- Cabs ventilation
- Remote cathodic protection monitoring
- Environmental standards

Total 'Other' non load related capex of £23.2M is forecast in the period 2005/6 – 2006/7 and a further £73M is forecast to be required in the forthcoming Price Control period:

[redacted]

[redacted]

[redacted]

5.4 TPA's Focus Areas for the Future Capex Review

Based on its analysis of the historic capex and from an initial review of the National Grid forward capex business plan, the TPA review team identified the following as key areas for the review:

TPA Key Areas for Review

Area	Key questions for the TPA review?
[redacted]	[redacted]
	[redacted]
	[redacted]
[redacted] Entry	[redacted]
[redacted] Exit	[redacted]
[redacted] Exit	[redacted]
SW Demand	Business case, project selection and timing
[redacted]	[redacted]
[redacted]	[redacted]
Unit Costs	Are unit costs reasonable for unapproved projects?
IPPC Related	Extent of programme and unit costs
	Relationship with compressor running hours forecast
Compressor and terminal asset replacement	Business case for the programme and unit costs
	Relationship with compressor running hours forecast and with IPPC programme
Other Major Infrastructure	Business case and costs for Humber crossing
Other Capex	Business case and costs
[redacted]	[redacted]
Telemetry and other SO capex	Reviewed in a separate TPA report
LNG	Reviewed in a separate TPA Report

5.5 Load-related drivers – overview of Business Case

5.5.1 TPA Methodology

The following table summarises the ongoing and proposed capex programme, with shaded cells indicating the capex approved and under detailed design/construction:

Ongoing and Proposed Capex Programme

Category	First 3 years of current PCR	Last 2 years of current PCR		Full 5 years of next PCR					
	02/03 – 04/05	05/06 - 06/07		07/08	08/09	09/10	10/11	11/12	Total
Entry – Capacity	161.0	538		329.9	144.4	21.8	5.6	0.4	502.1
Entry – Summer Flex	78.7	2.9		0.0	0.0	0.0	0.0	0.0	0.0
Exit – power generation	0.5	27.4		48.6	78.0	57.7	29.3	36.7	250.3
Exit – load growth	61.6	5.4		15.3	28.4	27.5	38.3	30.0	139.6
EC Harris Unit Costs	0	0		0.8	5.2	12.0	11.6	11.8	41.4
Total	***301.8***	***573.7***		**394.6**	**256.0**	**119.0**	**84.8**	**78.9**	***933.4***

Source: TPA Presentation of National Grid FBPQ Information, updated for 05/06 Actuals from TP1139

Given the scale of the capex programme underway by National Grid, with more that £1 billion forecast for entry capacity at Easington and Milford Haven alone, TPA has reviewed the background to this investment. To that end, the first part of this section reviews the way National Grid designs for additional entry capacity and sets out the key elements of the NTS Capacity regime that impact the level of National Grid capex.

5.5.2 Network Design Overview

Load related expenditure is either driven by entry (i.e. changes in the location and volume of gas supplies) or exit (i.e. changes in the location and volume of gas demand). Underpinning all load related investment, the Gas Act requires National Grid to meet all reasonable requests for a connection to the network, and National Grid's Licence stipulates that the system is to have sufficient capacity to meet all firm demand on the 1-in-20 peak day, with all interruptible loads turned off.

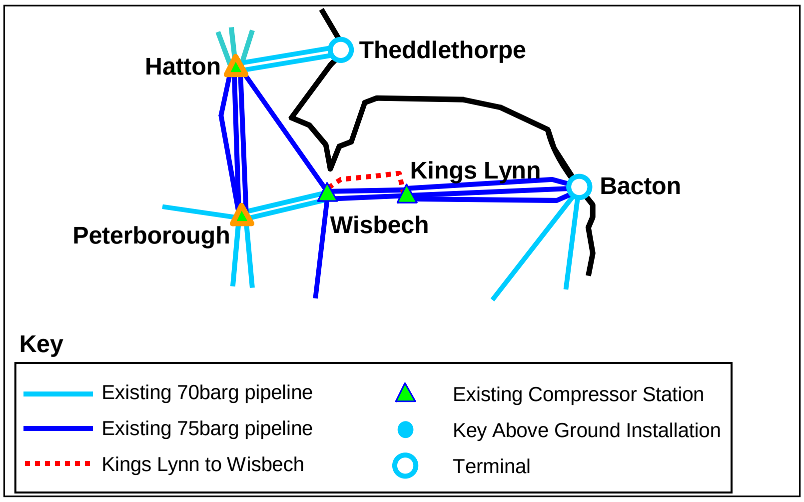
A 1-in-20 peak day is the level which is likely to be exceeded only in 1 day in every 20 years, having regard for at least 50 years of historical weather data.

In a network with more entry capacity than exit, the network planners have to make an assessment of likely co-incident gas flows that occur at both peak and off peak levels of demand as, on a daily basis the amount of gas entering the NTS must also exit. Network planning for investment on the NTS is done on a steady state analysis basis so linepack changes over the day are not seen during this process.

National Grid uses the UK-Continent Interconnector as the source of demand where there is excess supply and to provide additional gas where there is insufficient gas entering the system. TPA have assumed a similar approach to this in its analysis of the supply demand match, however National Grid apply differential pricing to establish flows, whereas TPA simply use the Interconnector as the balancing tool when there is a supply surplus, unconstrained by pricing differentials (see section 4.5.1). This means that, as an approximation, National Grid has to have the pipeline capacity to get gas to the Wisbech/Peterborough area and onto the Interconnector at Bacton or vice versa. TPA validated additional investment in such capacity in its historic capex report and supports this basic and fundamental design assumption.

Given this, any new entry points which appear to provide excess gas need to be able to transport such volumes to the Wisbech/Peterborough area, through new or existing assets.

Figure 16: The Network in the Wisbech/Peterborough Area



Source: National Grid

5.5.3 Entry and Exit Capacity

There is no relationship between sales of entry and exit capacity:

Entry capacity relates to the capacity available to the NBP (National Balancing Point) from beach or storage inputs and National Grid has to provide capacity, irrespective of level, though an economic test is applied in the form of entry auctions (see below). The destination for Entry gas approximates to Peterborough as discussed in 4.2 above.

Exit capacity relates to the 1 in 20 design level and is a function of the level of investment made by National Grid, together with the location and volumes of gas entering the NTS.

National Grid argues, and TPA agrees, that the ideal situation for competition in gas supply as UKCS gas production declines is for a significant excess of entry capacity over exit capacity (note that if this situation arises the requirement for a supply side component of the flow margin for transmission capacity may no longer be justified). This was not appropriate when all gas came from known reservoir basins in the UKCS but as pipeline and LNG imports grow, it is reasonable and necessary for excess entry capacity to be developed with consequent increases in capacity of the NTS.

Some additional entry capacity will relate to new gas supplies via pipeline or LNG and some will relate to new gas storage facilities as the de facto offshore UK storage field, southern north sea gas production, declines and has to be replaced by new storage assets, onshore and/or offshore assets

In addition, the nature of LNG and its relationship with shipping, with consequently difficult scheduling arrangements, means that there is forecast to be a significant excess of LNG re-gasification capacity. An analogy is cars and motorways. We all want a car because we want to go on the motorway sometimes at times of our choosing, but we are unlikely to all want to do this at the same time. The car is equivalent to the LNG reception facility, the motorway to the NTS. National Grid's key task is knowing who will be coming and when and where they want to go.

The obligations on National Grid manifest themselves in the NTS capacity regime, a summary of which is set out below:

5.5.4 Entry Capacity Baselines

As part of the 2002-2007 Price Control, Ofgem set Transmission Operator (TO) baseline levels based on the Maximum Physical Entry (MPEC) capacity at each system entry point. The methodology for setting these baselines was as follows:

(a) demand set at the 1 in 20 peak day level;

(b) supply scaled up at the entry point for which the baseline is being set, and scaled down at other entry points, until a constraint is reached at the relevant entry point;

(c) MPEC is set at the level at which the constraint is reached.

Baselines for entry points for LNG and storage facilities were set equivalent to the maximum output at that time of the LNG and storage facilities. This method of calculating TO baselines suggested a higher capability than is actually possible for most terminals (though not so much for St Fergus due to its location other than on low demand days) as it did not reflect actual capability when gas flows at neighbouring terminals was considered and the reduced capacity when demand is less.

As a result, SO baselines, which set the quantity of capacity that National Grid is required to offer, are deemed by Ofgem to be 90% of the relevant TO baseline.

Of the total SO baseline that is available at each location, no more than 80% can be offered in the Long Term System Entry Capacity (LTSEC) auctions - the remaining 20%, and any capacity that remains unsold following the LTSEC auctions, is retained for offer in the shorter-term auctions. In shorter term auctions, capacity can be made available from two years ahead down to the actual gas flow day.

5.5.5 Investment in Entry Capacity

National Grid says that investment in new Entry capex is required as a combination of the following:

(a) requirement to meet the 1 in 20 capacity obligation

(b) obligation to offer baseline capacity for sale and exposure to buy-back costs in the event that capacity which has been purchased cannot be physically delivered (e.g. Easington)

(c) signals for incremental capacity received through the LTSEC and other shorter term auctions (e.g. Milford Haven); and

Given the background the entry capacity regime set out above, TPA reviews below the investment proposed in the 7 years to provide additional entry capacity:

5.5.5.1 Investment in Baseline Capacity

In the event that National Grid forecasts that gas will enter a terminal at levels lower than the SO Baseline but higher than physical capacity, National Grid is able to make investment in new capacity. Whilst there is no guarantee that Ofgem will determine that this investment was reasonable and efficient, National Grid has made significant investment in these circumstances. [redacted] of such investment was made in relation to St Fergus Baseline capacity in the period 2002 – 2005 and [redacted] in relation to Bacton Baseline capacity.

[redacted]

Proposed Investment to reach Baseline Capacity

Terminal	2005/6-2006/7	2007/8 – 2011/12	Total
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Source: National Grid

[redacted]

[redacted]

[redacted]

[redacted]

Source:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Source: National Grid

[redacted]

[redacted]

[redacted]

[redacted]

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[redacted]

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[redacted]

[redacted]

[redacted]

Source: National Grid

[redacted]

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[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Terminal	2005/6-2006/7	2007/8 – 2011/12	Total
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Source: National Grid

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Source: National Grid

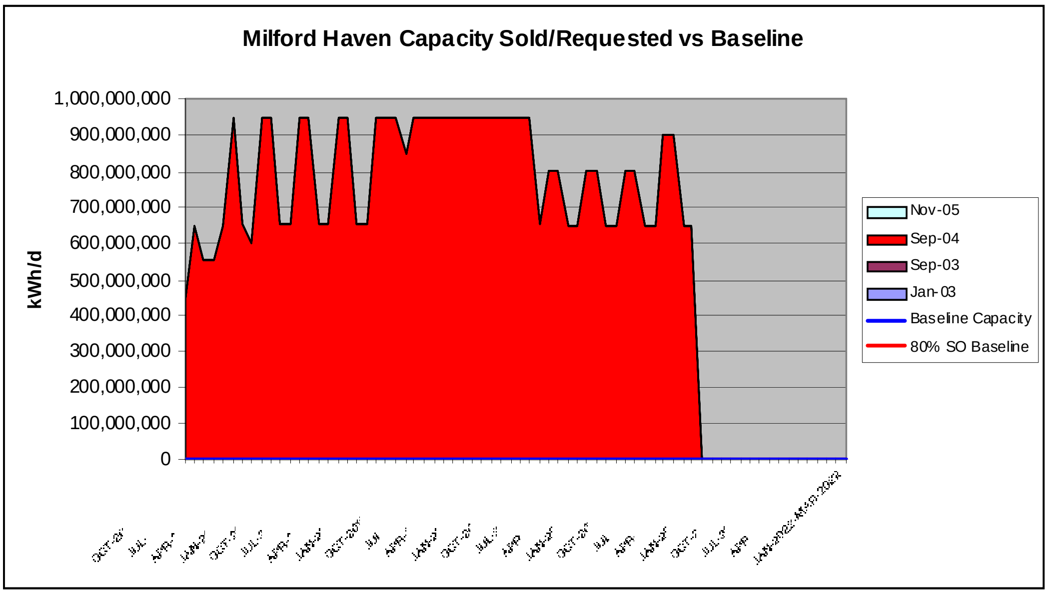
[redacted]

[redacted]

[redacted]

[redacted]

Figure 22 : Milford Haven LTSEC Auction Sales



Source: National Grid

National Grid is exposed to the costs of buying back any capacity that cannot be provided by the start date. Discussion of this is outside the scope of this report.

Milford Haven Capacity Expansion Programme

In order to provide entry capacity, the NTS is being extended to Milford Haven, and a new system entry point being created. In addition, in order to transport the gas to likely sources of demand, deeper reinforcement of the NTS is required, with a new pipeline and modifications to compressor stations in Gloucestershire. A significant level of investment is therefore required in order to provide a connection to the NTS, and sufficient capacity and compression to transport the gas from South Wales and into the remainder of the NTS. National Grid are building the following pipelines and compressor assets in order to provide the necessary capacity:

(a) Milford Haven to Aberdulais Pipeline (128km, 1200mm);

(b) Felindre Compressor Station (30MW);

(c) Felindre to Peterstow Pipeline (150km, 1200mm) + Regulator Installation;

(d) Peterstow to Tirley Pipeline (36km, 1200mm) + Regulator Installation;

(e) Wormington Compressor Station Modifications;

(f) Wormington to Honeybourne Pipeline (11km, 900mm); and

(g) Churchover Compressor Station Modifications.

[redacted]

Figure 23

[redacted]

Source: National Grid

[redacted]

5.5.5.3 Investment in Additional Capacity at an Existing System Entry Point

For an existing System Entry Point that may require additional capacity, the economic test set out above applies. The following investment is proposed in order to increase capacity at an existing System Entry Point:

Investment at existing entry points

Terminal	2005/6-2006/7	2007/8 – 2011/12	Total
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

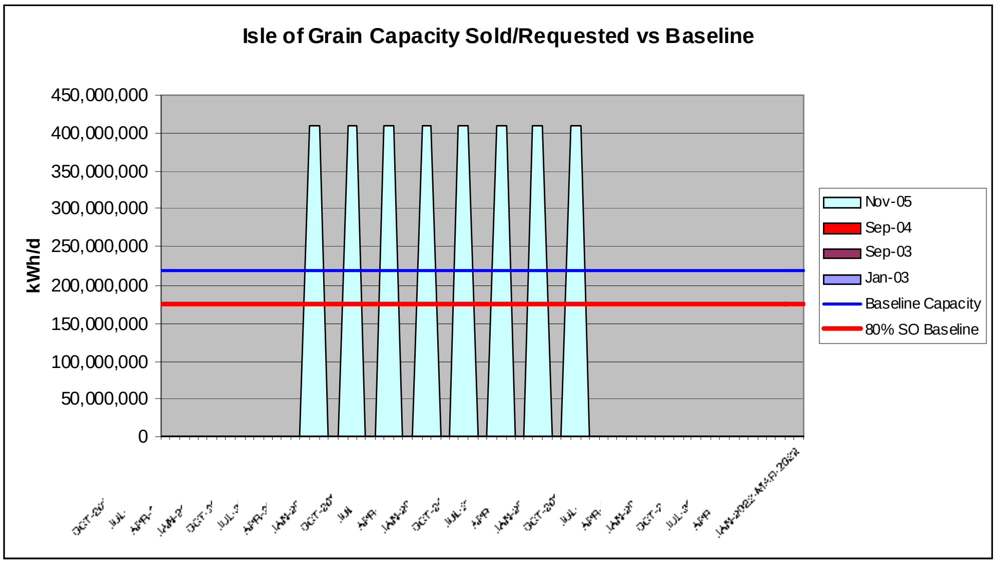
Source: National Grid

a) Isle of Grain

Isle of Grain Capacity Requirement

The first phase of the LNG facility at Grain became operational in July 2005, with a rate of delivery of up to 13 MCMD or approximately 4.5 BCM/Y. The second phase of the facility is currently under construction, and all of the additional capacity has been sold. This phase is expected to commission by the end of 2008 at an incremental rate of 24 MCMD, or approximately 9 BCM/Y. The graph below shows the capacity purchased in the Long Term system entry auction for Grain.

Figure 24: Ise of Grain LTSEC Auction Sales



Source: National Grid

At the LTSEC auctions in November 2005, sufficient bids were received to result in the release of 235 GWh (21.7MCMD) of Permanent Obligated Incremental Entry Capacity to shippers.

As the facility was known to be under construction, the Grain LNG facility is included in both the Global LNG and Transit UK scenarios. The investment to provide the incremental capacity signalled in the auctions is therefore required under all scenarios.

Baseline NTS entry capacity at Grain is insufficient to accommodate the aggregate gas flow rates for both phases of the LNG facility. For Grain, the actual physical capability of the existing network is closely aligned with the baseline quantity.

[redacted]

[redacted]

Figure 25

[redacted]

Source: National Grid

[redacted]

- [redacted]

b) Easington

Easington Capacity Expansion Requirement

In addition to the investment described above (Section 5.5.5.1), which allows the provision of baseline capacity at Easington, the supply scenarios all indicate a requirement for an increased requirement above baseline of capacity at Easington.

In the November 2005 auctions, National Grid received bids that demonstrated a requirement for incremental capacity, but were insufficient to automatically trigger the release of incremental capacity. [redacted] It is highly likely, therefore, that incremental capacity will need to be delivered by 2009, and National Grid anticipates receiving an incremental signal in the 2006 auctions.

[redacted]

[redacted]

Figure 26 : [redacted]

[redacted]

Source: National Grid

[redacted]

- [redacted]
- [redacted]

[redacted]

National Grid Business Case

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

5.5.6 Investment in Exit Capacity

Exit capacity investment is driven by the requirements of Special Standard Condition A9 (Pipeline System Security Standards, the 1-in-20 condition). This requires the production of a forecast of daily gas demand likely to be exceeded only in 1 day in a period of 20 years.

For the NTS there are 2 different types of customers:

- NTS Directly Connected loads, mostly power generators, with the 1 in 20 capacity equal to the maximum contracted value, the System Offtake Quantity
- Distribution Networks connected loads which aggregate their demands (including domestic consumers) to establish a 1 in 20 maximum capacity requirement

5.5.6.1 Investment in Exit Capacity for a New Directly Connected Load

Where exit investment is required specifically to provide capacity for a single directly connected incremental load (usually a new directly connected consumer such as a gas-fired power station), the investment is underpinned by an Advanced Reservation of Capacity Agreement ("ARCA") which places financial obligations on the consumer or their shipper. This financial commitment forms the economic signal to proceed with any necessary investment works and has the same purpose as the entry auctions.

The following investment is proposed in order to create New System Exit Points:

Investment for New Exit Points

New Directly Connected Load	2005/6-2006/7	2007/8 – 2011/12	Total
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Source: National Grid

Given the excess of entry capacity, it is possible that a number of new power stations can be supplied with no reinforcement and this is the case for power stations in the centre of the network such as [redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
					[redacted]

Source: National Grid and TPA

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

(a) [redacted]
(b) [redacted]
(c) [redacted]
(d) [redacted]
(e) [redacted]
(f) [redacted]
(g) [redacted]

Figure 27: [redacted]

[redacted]

Source: National Grid

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Figure 28

[redacted]

Source: National Grid

[redacted]

- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

TPA Commentary

There are a number of questions to be considered:

- [redacted]
- Is it reasonable to assume a combined scenario of:
  - no gas input flows at [redacted]
  - 1 in 20 demands [redacted]
- Full load requirements at the [redacted] power station?
  - If the answer is yes, over what duration will that scenario exist?
- Finally, what flows would be available without reinforcement in such a scenario

First, the combined scenario. National Grid has to design for 1 in 20 conditions and it is therefore necessary for the assumption to be modeled that on a 1 in 20 peak day there will be maximum electricity demand at the [redacted]. However, TPA believes that it is highly unlikely that on such a 1 in 20 peak day there would be no gas inputs at [redacted] given the third party access exemption conditions that apply to both the [redacted] and [redacted]. It is of course possible that this could be the case. [redacted]

If there were no gas flows from [redacted] on a 1 in 20 peak day, would this cause constraints on the NTS and cause National Grid to breach its Safety Case?

As a matter of principle, provided there is local LNG storage in significant quantities (for example equal to storage of at least 5 days of send-out), TPA does not believe there are any grounds to assume that LNG is any less likely to be re-gasified and input into the NTS than pipeline sources of gas will not appear. It may be that the LNG supplies will actually be more reliable due to their modern construction, levels of standby capacity and generally simple process compared to existing UKCS offshore/onshore systems.

Whilst TPA does not believe the combined scenario is realistic, what are the consequences if it does happen for a 24 hour period (the 1 in 20 day)?

[redacted]

[redacted]

Source: National Grid

[redacted]

[redacted]

Given that, and additional flows from the NTS at Tirley, TPA believes that it would be possible to supply the [redacted] without the need for any reinforcement and hence TPA does not believe this capex is necessary.

TPA believes that National Grid should carry out a study to:

- show how the load could be supplied on the 1 in 20 day using linepack and the existing network.
- [redacted]
- review the levels of local LNG storage and whether there are scenarios were the operators will have empty LNG tanks around a 1 in 20 peak day
- review the likely levels of reliability of the new LNG facilities (benchmarking to US and far East) compared to the existing UKCS offshore/onshore system
- review the NTS to understand how no shipper inputs on a 1 in 20 day ([redacted]) whether for commercial reasons (price related) or due to reliability would impact the 1 in 20 obligation.

Together, TPA believes that the above study will make a satisfactory case that compliance with the Safety Case does not require investment in this case and as a result this investment is not required. If as a result of such study it is determined, for example by the HSE under the Safety Case, then it would be appropriate to consider whether commercial arrangements could be put in place with shippers at [redacted] in order to satisfy the HSE whilst minimizing capex. TPA believes this would be an appropriate SO incentive arrangement at that time.

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]
  - [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

TPA Commentary

[redacted]

TPA understands that there are existing arrangements in place which allow National Grid to access LNG from the [redacted] capacity holders ([redacted]). This is also an option to be considered on the 1 in 20 peak day.

TPA believes that, as with [redacted], there are no grounds for assuming that LNG facilities should be treated in a different way to existing pipeline supplies. [redacted], capacity in the LNG facilities owned by National Grid have been sold to a significant and diverse group of shippers. TPA believes that it is highly unlikely that on a 1 in 20 peak day these shippers would not be inputting gas into the NTS.

As in relation to [redacted], TPA believes that National Grid should carry out a study to:

- show how the load could be supplied on the 1 in 20 day using linepack and the existing network.
- review the third party access arrangements in place with the National Grid facilities and any undertakings given by existing and future capacity holders and the consequences of withholding gas at times of system stress
- review the levels of local LNG storage and whether there are scenarios were the operators will have empty LNG tanks around a 1 in 20 peak day
- review the capacity available as a result of the arrangements with [redacted]
- review the impact of [redacted]
- review the likely levels of reliability of the new LNG facilities (benchmarking to US and far East) compared to the existing UKCS offshore/onshore system
- review the NTS to understand how no shipper inputs on a 1 in 20 day (eg [redacted]) whether for commercial reasons (price related) or due to reliability would impact the 1 in 20 obligation

Together, TPA believes that the above study will make a satisfactory case that compliance with the Safety Case does not require investment in this case and as a result this investment is not required. If as a result of such study it is determined, for example by the HSE under the Safety Case, then it would be appropriate to consider whether further commercial arrangements could be put in place with shippers at the [redacted] in order to satisfy the HSE whilst minimizing capex. TPA believes this would be an appropriate SO incentive arrangement at that time.

5.5.6.2 Investment in Exit Capacity for a Gas Distribution Network

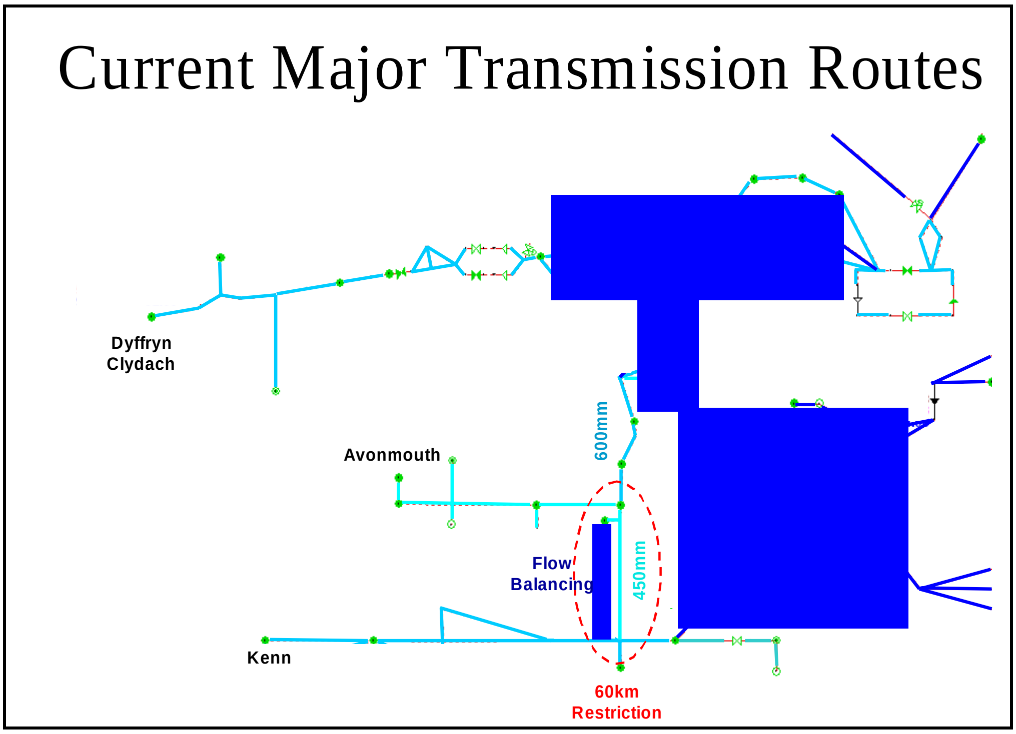
The following investment is proposed in order to provide additional firm exit capacity for the SW LDZ:

LDZ	2005/6-2006/7	2007/8 – 2011/12	Total
[redacted]	[redacted]	[redacted]	[redacted]

Source: National Grid

The South West quadrant of the NTS comprises of the majority of the South West LDZ, parts of the Southern and South East LDZs , and numerous directly connected loads. The quadrant is loosely defined as being the area of the NTS bounded by Wormington AGI on feeder 14, and Aylesbury compressor on feeder 7. This section of the NTS is a purely importing section, with the only source of supply being the [redacted] facility, such that gas only ever flows into this section to service the demand. As such, any investment in this section of the network is clearly to provide exit capacity.

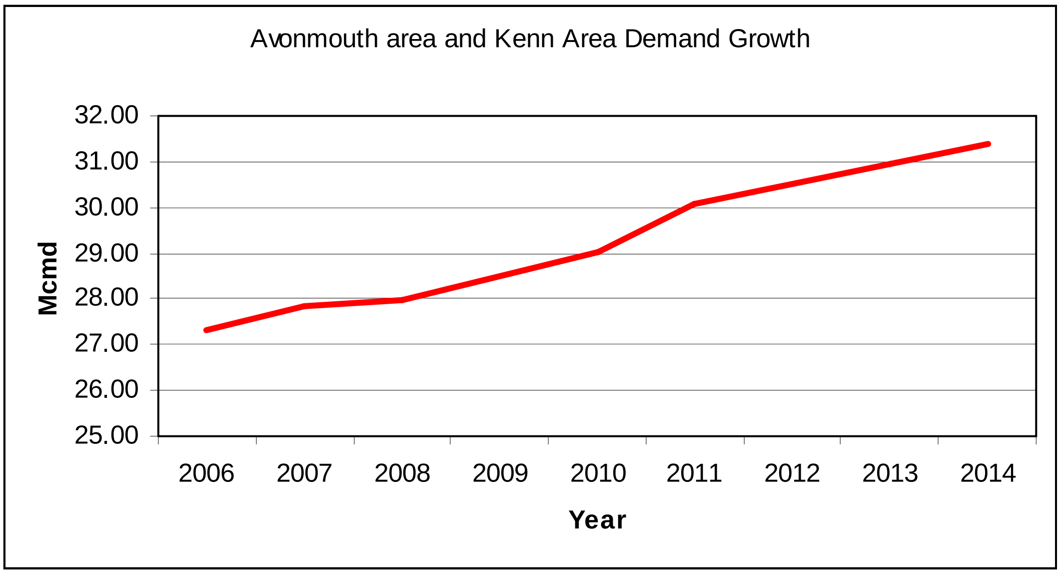
Figure 30



Source: National Grid

The forecast 1-in-20 peak day growth rates applicable to the South West quadrant are shown in the chart below. The DN load growth associated with the FBPQ capex was forecast (as shown in the graph below) based on gas prices with oil at $35/bbl.

Figure 31: Forecast DN Load Growth



Source: National Grid TP4083

Avonmouth area includes Cirencester, Easton Grey, Littleton Drew, Pucklechurch and Seabank.

Kenn area includes Mappowder, Ilchester, Aylesbeare, Kenn and Lyneham.

In their FBPQ submission, National Grid forecast load growth in the South West LDZ is forecast to be from 26.9MCMD to 29.0 MCMD in 2011/12. Whilst this rate of demand growth is no greater than the demand on the rest of the system, the South West is the weakest part of the NTS, given its remoteness from all of the major entry points, such that even moderate demand growth can give rise to the need to reinforce the NTS significantly.

In addition to this, National Grid says that the change in the pattern of supplies forecast by the new supply scenarios drives a need for reinforcement. The South West quadrant is capable of accepting gas supplies from two pipeline routes into the South West quadrant. With supplies at [redacted], more supplies into the South West will be fed from there, via the western leg of the two feeds into the South West quadrant from Wormington. As a result of the reconfiguration of pipelines and compressors in the Wormington area (part of the [redacted] reinforcement scheme) National Grid say there will be lower pressures in the South West quadrant which will ultimately create a need in 2010 for reinforcement of the southern feeder from Aylesbury.

National Grid says that the new supplies into South Wales and the South East reduce the probability of constraints in those areas which means that expenditure is not required in those areas to support growing demand. This beneficial effect is not evident in the South West.

The relevant planned investment comprises:

(a) Wormington to Sapperton pipeline (2008/09, 42km, 900mm);

(b) Easton Gray to Litleton Drew pipeline (2010/11, 12km, 900mm);

(c) Sapperton to Easton Gray pipeline (2009/10, 18km, 900mm);

(d) Mappowder to Ilchester pipeline (2010/11, 33km, 900mm);

(e) East Illsley to Barton Stacey (2010/11, 52km, 900mm).

The total cost in the forthcoming Price Control period of the investment listed above is just under £140M with £2.6M incurred in the present period

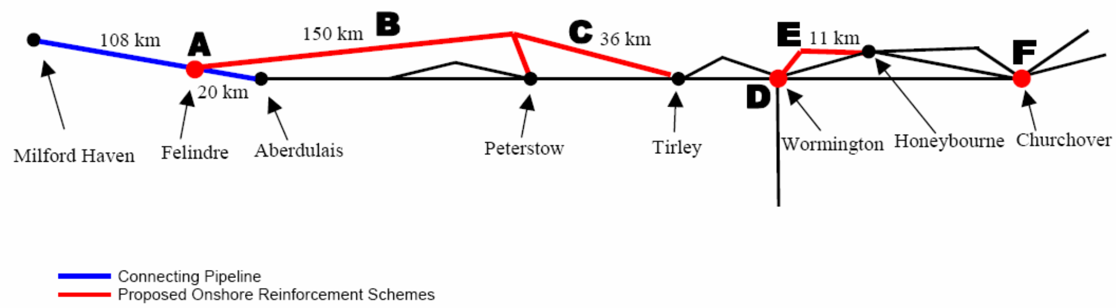
Wormington to Sapperton

National Grid says that the alternatives to Wormington to Sapperton in 2008 were to either;

- build Mappowder to Ilchester and Lockerley extra power (a more expensive solution); or
- constrain additional volumes of CLNG at Avonmouth at a cost of [redacted] to defer the reinforcement by one year.

National Grid says that the CLNG cost appears attractive in deferring a [redacted] but there are other factors to consider. Wormington to Sapperton (42km x 900mm) has been bundled with Wormington to Honeybourne (11km x 900mm) for tender as they are in the same geographical location (see drawing below) and would be constructed in 2008 (the year after the completion of the main Milford Haven reinforcement).

Figure 32: Wormington to Sapperton



A	Felindre New Compressor Station (30MW)
B	Felindre to Peterstow Pipeline (150km, 1200mm) + Regulator Installation
C	Peterstow to Tirley Pipeline (36km, 1200mm) + Regulator Installation
D	Wormington Compressor Station Modifications
E	Wormington to Honeybourne Pipeline (11km, 900mm)
F	Churchover Compressor Station Modifications

Source: National Grid

National Grid argues that as a result of bundling these 2 projects, it is not economic to defer Wormington to Sapperton.

TPA Commentary

TPA believes that if the DN load growth materializes and the CV is as forecast by National Grid then the suite of projects appears to be reasonable.

However, National Grid have indicated that the latest gas demand numbers caused by higher gas prices have delayed the pipeline projects by 2 years and that there is evidence that domestic demand has been reduced as a result of increasing gas prices and the general publicity related to gas supplies.

Given that the incremental load (raising the SW demand) is only required for the 1 in 20 day (the investment is not required for seasonal normal temperatures), TPA believes it is critical that all avenues are investigated in order to defer this investment, such as reduction of the level of Flow Margin, use of constrained LNG, Exit Reform and contracting with [redacted] shippers. Higher gas prices and DTI energy reduction initiatives may also mean that it is never required.

TPA believes that, at the Phase 1 Conceptual Design stage it was efficient to combine the [redacted] SW DN demand related project, Wormington to Sapperton with the [redacted] entry related project, Wormington to Honeybourne. However, there are significant utilization risks if Wormington to Sapperton is built for 2008 in anticipation of future demand growth that does not materialize or could be satisfied in alternative ways ([redacted]). Given the dramatic gas price increase since award of the Stage 1 contract and the latest forecast of [redacted] for this project, TPA believes National Grid should explore breaking the contract into 2 and delaying the Wormington to Sapperton Project for at least 2 years.

Further, TPA recommends that National Grid and Ofgem use the South West DN load growth/NTS capacity issue in order to inform the shipper community in relation to Exit Reforms with the prize being that none of the forecast SW DN projects are built. TPA believes that Ofgem should consider an SO incentive on National Grid in order to achieve this. [redacted]

Given the uncertainty related to gas prices and the above factors, TPA believes that as a central scenario, the capex required for SW DN load growth should be reduced by [redacted] (capex in last 2 years of the next PCR period), but with a prize of [redacted] remaining to be saved as a result of Flow Margins, Exit Reform/SO Incentive, Constrained LNG (with an appropriate allowance to National Grid to cover any efficiently incurred costs on projects that are no longer required)

[redacted]

5.5.7 TPA Commentary on Load Growth Capex

Reference	Title	Description	Commentary
5.5.7.1	[redacted] reinforcement	Reinforcement projects for [redacted]	TPA believes the overall reinforcement proposed is reasonable, with no better options to provide the necessary capacity for [redacted].
5.5.7.2	Entry regime	National Grid provides and funds the connecting pipeline for a New System Entry Point	Given competition in pipelines and a level playing field for construction of these, there is no reason why the new connection should have been be funded and operated by National Grid with capital costs pushed onto UK consumers.
5.5.7.3	[redacted] reinforcement	The Pannal to Nether Kellett cross Pennine link	This is a difficult pipeline and may not be any better than the alternative of building infrastructure to go south towards Alrewas. However, it is a reasonable option. TPA would have liked National Grid to have [redacted] pipeline to have been considered as an alternative means of providing NTS flexibility.
5.5.7.4	[redacted]	[redacted]	OK
5.5.7.5	[redacted] Reinforcement	Reinforcement to provide capacity	OK
5.5.7.6	[redacted] Reinforcement	Reinforcement to provide capacity	OK
5.5.7.7	[redacted] Reinforcement	[redacted]	TPA believes that the case for this investment has not been made and has proposed that National Grid carries out a study to establish that the investment is not required. If as a result of such a study the HSE determines a need for this investment, then National Grid and Ofgem should consider a new SO incentive to reduce the level of capex required . [redacted]
5.5.7.8	[redacted] Reinforcement	Reinforcement to supply if no LNG at Milford	TPA believes that the case for this investment has not been made and has proposed that National Grid carries out a study to establish that the investment is not required. If as a result of such a study the HSE determines a need for this investment, then National Grid and Ofgem should consider a new SO incentive to reduce the level of capex required . [redacted]
5.5.7.9	[redacted] Reinforcement	Impact of Higher Gas Prices, Exit Reforms and Flow Margin	TPA recommends that National Grid and Ofgem use the South West DN load growth/NTS capacity issue in order to inform the shipper community in relation to load growth (higher gas prices), Exit Reforms, Flow Margin and Constrained LNG at [redacted] with the prize being that none of the forecast SW DN projects are built.

Reference	Title	Description	Commentary
			TPA believes that Ofgem should consider an SO incentive on National Grid in order to achieve this [redacted] Given the uncertainty related to gas prices and the above factors, TPA believes that as a central scenario, the capex required for SW DN load growth should be reduced by £68.3M (capex in last 2 years of the next PCR period), but with a prize of £71.3M remaining to be saved as a result of Exit Reform/SO Incentive (with an appropriate allowance to National Grid to cover any efficiently incurred costs on projects that are no longer required). TPA believes that Wormington to Sapperton should be delayed at least for 12 months to create the opportunity to save as much of the £139.6M capex as possible whilst complying with the Licence and Safety Case

5.6. Non - Load Related Drivers – Overview of Business Case

5.6.1 TPA Methodology

Given the scale of the non-load related capex programme underway by National Grid, with more that £300 million forecast for the next 7 years, TPA has carried out a detailed review of the asset management function with National Grid's Network Strategy department, see HBPQ Report.

With respect to IPPC, the conclusions of this review are that the outcome is generally efficient and the principles agreed with the environmental regulators are sound.

However, with respect to the compressor and terminal asset replacement programme, there are three factors that TPA believes are key to determining the efficient level of replacement:

- the asset health monitoring process is relatively new – does it provide sufficient confidence to justify the requirement for a significant increase in replacement expenditure in all cases.
- the major reduction in running hours forecast for 2006 – 2011
- the interaction with the IPPC capex programme.

TPA has also reviewed [redacted] other non load related capex at a high level.

TPA produced an initial view based on information received from National Grid. National Grid has responded to TPA's initial view with additional information. TPA then revised its view, as appropriate, to take into account this additional information. Each area of non-load capex therefore contains final sections as follows:

- TPA Commentary
- National Grid additional information
- Revised TPA Commentary

5.6.2 Categories of non load related drivers

Non-load related expenditure is divided into five sub-categories:

(a) IPPC (NOX) emissions related investment (including metering)

(b) Asset replacement (compressor station and terminals)

(c) Other major capex

(d) Other non load related capex

[redacted]

Of these, the two categories that comprise the majority of the expenditure are IPPC (NOX) emissions related investment and compressor serviceability investment, the drivers for which are discussed in more detail below.

National Grid's forecast non load related expenditure for the last 2 years of the present PCR period and for the full 5 years of the next PCR is shown below:

Non-Load Related Forecast Expenditure

Category	First 3 years of current PCR	Last 2 years of current PCR		Full 5 years of next PCR					
	02/03 – 04/05	**05/06 - 06/07**		**07/08**	**08/09**	**09/10**	**10/11**	**11/12**	**Total**
Compressor Emissions	0	69.5		68.8	46.5	28.6	19.7	19.7	**183.3**
Asset Replacement	46.9	25.4		24.6	23.9	26.3	22.5	22,5	**141.6**
Other Major capex	0	0		23.1	9.4	16.3	3.3	0.5	**52.6**
Other Non load Related	9.7	23.2		18.6	20.3	12.9	10.0	11.2	**73.0**
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	56.6	123.7		139	104	88	59.4	62.3	**470**

Source: TPA Presentation of National Grid FBPQ Information

5.6.3 Integrated Pollution Prevention and Control (IPPC) related investment (forecast £69.5M in 05/6 – 06/7 and £183.3M in next PCR period)

Business Case

National Grid have negotiated an agreement with the EA and SEPA to invest at those sites causing the highest level of emissions, starting with a first phase of two sites in the current Price Control period, and continuing with a second phase of seven more in the next period. Investment of £180M is forecast to be required in the forthcoming Price Control period.

The following investment is proposed in order to reduce the NOX emissions from a number of stations:

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]	[redacted]
[redacted]		[redacted]	[redacted]
[redacted]		[redacted]	[redacted]
[redacted]		[redacted]	[redacted]
[redacted]		[redacted]	[redacted]
[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Source: National Grid

TPA Commentary

TPA believes that National Grid have achieved an acceptable and efficient outcome with the EA and SEPA. The key uncertainties relate to:

- The extent of the programme (which depends on the running hours of the compressor stations for year 2008) :
- The industry accepted norm is a cost of £4,000 per tonne of NOX abaited. At present there are a number of sites that are forecast to have much higher costs and hence funding would not be required [redacted]. Reduction of £51.6M
- The efficient capital costs of the programme:
- Which includes the interaction with the serviceability capex programmes such as replacement of control systems and other compressor station equipment.

National Grid additional information

Cost per tonne of NOX abated

The range of cost of NOX in terms of abatement is published within the European BREF note on Economic and Cross Media Effects and has been supplied. This has identified costs in the range of €4000 and €12000 per tonne of abatement.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] National Grid acknowledge that there remains uncertainty over the need for replacement at this particular site but say that other sites would become candidates. [redacted] National Grid are concerned that the EPA and SEPA would force the replacement at even more sites than we allowed for in our FBPQ. National Grid suggests that a facility be created to allow additional funding in the event that the EA or SEPA take enforcement action at any of our compressor sites.

Revised TPA Commentary

Cost per tonne of NOX abated

If there is not an accepted 'norm', then TPA believes that National Grid should benchmark the cost per tonne that it is incurring against other UK businesses in order to confirm that it is on a level playing field with other parts of British industry.

[redacted]

[redacted] TPA does not believe the high St Fergus flow scenario is credible but does accept the principle that if EA or SEPA forces replacement then such investment should be funded as part of the TO RAV, provided the cost per tonne of NOX saved applied to the NTS is no higher than applied elsewhere in British industry.

5.6.4 Related to Replacement of Compressor and Terminal Assets (forecast £25.4M in 05/6 – 06/7 and £119.7M in next PCR period)

5.6.4.1 Background

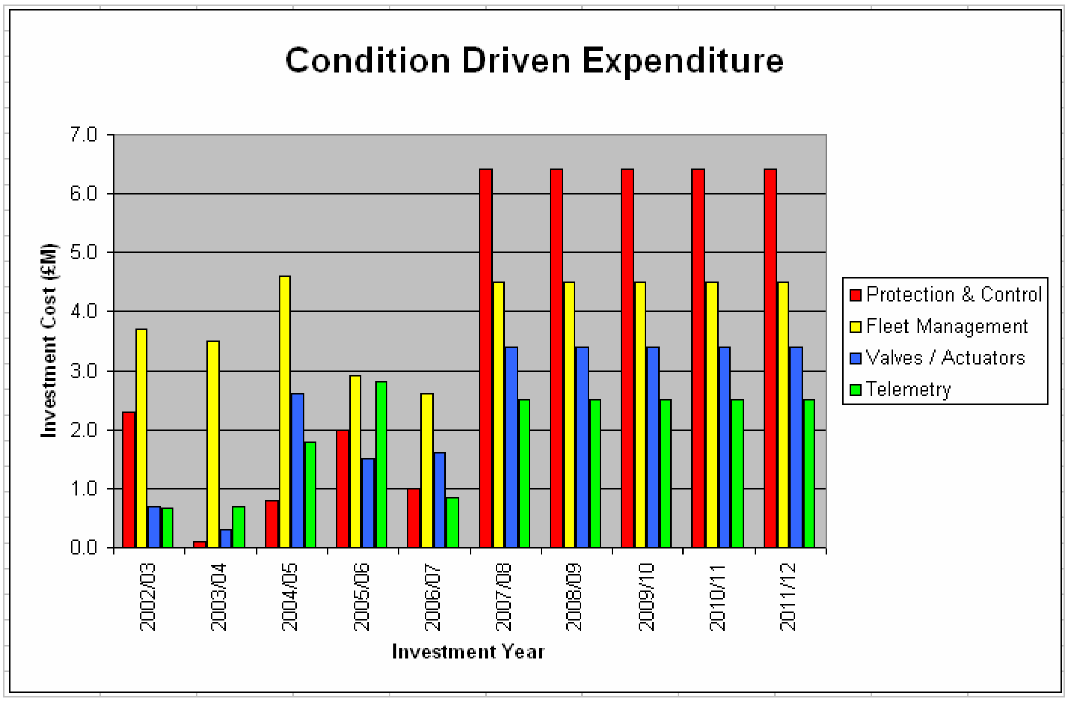
National Grid says that this is an emerging area. Expenditure for "serviceability" as it has been known in the past has historically formed a relatively small part of overall expenditure on the NTS. However, National Grid believes there are now a number of drivers for the development of a more systematic approach to asset replacement on the NTS, including:

- the ageing of the asset base driving the need to be able to develop long term replacement plans in order to manage the asset base, ensure replacement is deliverable and ensure the reliability and environmental and safety performance of the assets; and
- the merger between National Grid and Transco leading to the development of a more common approach to asset management, condition monitoring and development of long term replacement plans.

National Grid is developing its asset management approach, and is moving towards the longer established approach utilised by the electricity transmission side of the business, using detailed condition information to inform on the anticipated life of the assets. The early stage of development of this more systematic approach has been used to inform the base case forecast expenditure for the forthcoming Price Control period.

National Grid forecasts an increase in the expenditure required for asset replacement driven by asset condition over the forthcoming Price Control period to approximately £142M in the five year period (£119.7M in TO).

Figure 33



Source: National Grid

Category of repex	2005/6-2006/7	2007/8 – 2011/12	Total
Protection and control systems	3	44.8	47.9
Rotating machinery power train	8.4	22.9	31.3
Valves and actuators	4.6	17.1	21.7
Total	**16**	**84.8**	**100.9**

Source: National Grid

Compressor and terminal telemetry replacement capex is reviewed in TPA's SO Report

5.6.4.2 Compressor station running hours

Figure 34

[redacted]

Source: National Grid

The graph above (from TPA4096) shows the forecast running hours (based on the 2005 plan) and the relationship with the proposed repex programme [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Given that general background, the next sections review the four areas of compressor and terminal asset replacement proposed for the forthcoming PCR period.

5.6.5 Business Case for Compressor Asset Replacement

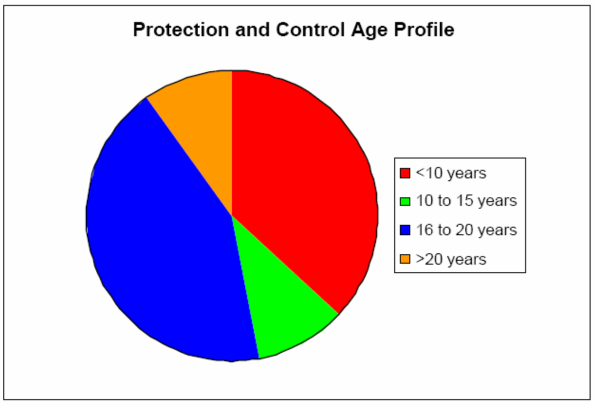
a) Protection and control systems

Protection systems comprise a number of individual elements, which protect the gas transmission equipment under fault conditions including fire and gas detection systems and controlled emergency shutdown systems which operate ahead of catastrophic failure.

Control equipment is made up of a number of discrete systems, which enable the gas transmission equipment to be operated locally or remotely and provide information on the operational state of pipelines, compressors and terminals.

The chart below shows, over 50% of the total protection and control system populations are over 15 years old and therefore a large proportion of both technologies is nearing or exceeds its anticipated life. The main drivers to replace protection and control are obsolescence, unreliability and known life limiting factors.

Figure 35



Source: National Grid

Obsolescence occurs because the equipment is no longer manufactured – and therefore support from the original equipment manufacturers is in decline and in some instances no longer available. National Grid deems equipment obsolete when the manufacturer has withdrawn support and/or internally we cannot provide the necessary maintenance support due to lack of expertise or spares. Replacement due to reliability arises from poor equipment performance, which has a direct impact on system performance.

During the current PCR period, the protection and control system replacement rate has been relatively limited as, in general, the performance of the equipment has been satisfactory. However, National Grid believes there is an increasing need to replace protection and control systems due to:

- evidence of an increasing number of defects being identified on the population of protection and control equipment; and
- limited availability of technical support and spares due to the original equipment manufacturers withdrawing their support.

National Grid say that around 10% of all reported defects between January 2001 and October 2005 are associated with control and protection faults that have resulted in failures of compressor units to start or running failures (trips). National Grid argue that this increase in defects is a leading indicator of the need to increase the programme of replacement in the forthcoming Price Control period, with is an increasing risk that:

- safety protection systems may fail on demand, resulting in damage to plant, an environmental incident or, in worst case, exposure of personnel to unnecessary safety risks;
- multiple compressor stations or terminals may have to be declared unavailable;
- National Grid's obligation to provide sufficient transportation capacity would be jeopardised, resulting in costs incurred through capacity constraints.

Candidates for protection and control system replacement are ranked in priority order of risk to the NTS. The replacement is not based upon age itself, but upon the consequences of failure and an assessment of the risks associated with operating obsolete systems that are or could become unsupportable.

Protection and Control Capex

During the current Price Control, £9.4M has been spent on protection and control system replacement schemes. For the forthcoming Price Control period, it is planned to increase this spend to £32.1M as a consequence of the increased obsolescence of systems and unreliability issues. This was originally planned at a constant rate of £6.4M per annum to deliver the replacement of two protection and control system replacements per year, as identified and prioritised by the Gas Asset Replacement Decision Support Tool.

However, in order to minimise system access requirements, the schemes have been aligned with other planned capital schemes.

Based upon the output from the Decision Support Tool, the top ten sites identified for investment in Protection and Control System replacement have been determined, and are shown below, along with the schemes with which they are aligned.

Top ten Sites for Protection and Control Investment

Site Name	Year	Comments
Churchover	2008/09	To be replaced during the South Wales Reinforcement Strategy.
Warrington	2009/10	To be replaced during proposed Phase 2 Emissions Reduction Strategy.
St.Fergus	2008/09	To be replaced during proposed Phase 1 Emissions Reduction Strategy.
Bathgate		Although identified as a candidate for replacement the required duty of this site has been replaced by Avonbridge.
Moffat	2009/10	To be replaced during proposed Phase 2 Emissions Reduction Strategy.
Carnforth	2008/09	To be replaced during proposed Phase 2 Emissions Reduction Strategy.
Kirriemuir	2008/09	To be replaced during proposed Phase 1 Emissions Reduction Strategy.
Peterborough	2008/09	To be replaced during proposed Phase 2 Emissions Reduction Strategy.
Hatton	2008/09	To be replaced during proposed Phase 2 Emissions Reduction Strategy.
Scunthorpe	2009/10	To be replaced as part of the Protection & Control System Replacement Strategy.
Huntingdon	2008/09	To be replaced during proposed Phase 2 Emissions Reduction Strategy.

Source: National Grid

TPA Commentary

TPA believes that the general approach adopted by National Grid is reasonable and efficient in relation to the replacement of protection and control equipment.

In relation to IPPC or Milford Haven related assets, TPA supports the business case. [redacted]

National Grid additional information

[redacted]

Revised TPA Commentary

[redacted]

b) Gas generator and power turbine replacement

National Grid is proposing replacement of assets within the following categories:

(i) the Gas Generator which supplies the power for the power train;

(ii) the Power Turbine, which uses the hot exhaust gases from the gas generator to pass through blades causing the rotor blades and shaft to turn; and

TPA has reviewed the replacement policy for gas generators and power turbines as part of its review of the Network Strategy function in the historic capex and opex review and is generally content that it is reasonable, subject to individual assessment of utilization.

i) Gas Generator Capex

During the period up to 2006/07, £17.9M will be spent on Gas Generator major overhaul schemes. A slightly lower level of expenditure (£13.1M) is forecast to be required on Gas Generator major overhaul schemes in the forthcoming Price Control period, allowing the major overhaul of 16 generators.

The table below shows the location and type of gas generators proposed for either mid-life or full-life major overhaul in the plan period. These candidates are based on hours run to-date and a forecast of running hours during the next five years.

Gas Generators - Candidates for Overhaul

Location	Gas Generator Type
Aberdeen Unit B	GE LM2500
Aberdeen Unit C	GE LM2500
Bishop Auckland Unit B	GE LM2500
Carnforth Unit C	GE LM2500
Wooler Unit A	GE LM2500
On Stand/Spare	GE LM2500
Hatton Unit C	Rolls Royce RB211
St.Fergus Unit 2A	Rolls Royce RB211
Kirriemuir Unit D	Rolls Royce RB211
Warrington Unit B	Rolls Royce RB211
Hatton Unit B	Rolls Royce RB211
Hatton Unit A	Rolls Royce RB211
Diss Unit A	Rolls Royce Avon
Scunthorpe Unit B	Rolls Royce Avon
St.Fergus 1A	Rolls Royce Avon
Wormington Unit A	Rolls Royce Avon

Source: National Grid

TPA Commentary

[redacted] TPA believes that 8 of the 16 overhauls are unlikely to be required, giving a reduction of £6.5M. [redacted]

National Grid additional information

[redacted]

Revised TPA Commentary

[redacted]

[redacted]

ii) Power Turbine capex

During the period from 2002/03 to 2007/08, £1.6M was invested in purchasing a new strategic spare Vectra power turbine. [redacted]. Following the review of Technical Asset Lives, National Grid propose to increase the investment of power turbine major refurbishment to £9.8M over the forthcoming Price Control period. This additional investment is required to refurbish the power turbines that are now significantly beyond the revised Technical Asset Life.

The strategy to deliver this increase in expenditure is to develop a "travelling spare approach", where strategic spare power turbine internal components will be installed and the parts removed, taken away for refurbishment and used during the next planned major refurbishment.

The table below shows the power turbines scheduled for either mid-life or full-life major overhaul in 2007/08 -2011/12

Power Turbines - Candidates for Overhaul in 07/08

Location	Power Turbine Type	Age (years)
St.Fergus Unit 2A	GEC ERB-122	25
Moffat Unit B	GEC ERB-122	27
Wisbech Unit A	GEC ERB-122	27
Wisbech Unit B	GEC ERB-122	27
St.Fergus Unit 2D	GEC ERB-122	28
Diss Unit A	Cooper RT48	28
Diss Unit B	Cooper RT48	28
Diss Unit C	Cooper RT48	28
Kirriemuir Unit A	GEC EAS-133	29
Kirriemuir Unit B	GEC EAS-133	29
Kirriemuir Unit C	GEC EAS-133	29
St.Fergus Unit 1A	GEC EAS-133	30
St.Fergus Unit 1B	GEC EAS-133	30
St.Fergus Unit 1C	GEC EAS-133	30
St.Fergus Unit 1D	GEC EAS-133	30
Cambridge Unit A	Cooper RT48	32
Cambridge Unit B	Cooper RT48	32
Chelmsford Unit A	Cooper RT48	33
Chelmsford Unit B	Cooper RT48	33
Kings Lynn Unit A	GEC EAS-133	33
Kings Lynn Unit B	GEC EAS-133	33
Churchover Unit A	Orenda OT370-2K	34
Churchover Unit B	Orenda OT370-2K	34
Alrewas Unit A	Cooper RT48	36
Alrewas Unit B	Cooper RT48	36

Source: National Grid

TPA Commentary

[redacted]

National Grid additional information

[redacted]

Revised TPA Commentary

[redacted]

[redacted]

[redacted]

c) Valves and Actuators

Valves are of steel construction with either welded or flanged connections to the connecting pipework. They range in size from 1” to 48” and are fitted with vent/sealant lines to enable safe venting of the body cavity and injection of lubricant for safe, efficient sealing. A valves primary function is to provide safe, secure plant isolation and to control the gas transmission system.

Actuators provide the motive force to operate the valves. Actuators are operated from various sources such as gas directly from the high pressure transmission system, gas via pressure reducing systems, hydraulics or electric motors. The actuator controls are located within steel actuator cabinets.

The replacement of valves and actuators is prioritised based upon condition. To date valve and actuator replacement has been limited, as their performance has generally been satisfactory.

However, an increasing number of defects are now being identified on the population of valves and actuators, with approximately 7% of all reported defects on the NTS being related to valves. More than 200 defects have been identified on valves and actuators since 2001, not including those identified during routine maintenance and testing. In addition to these defects, specific corrosion issues on valve actuator cabinets have been identified through condition assessment. Therefore, a program of valve refurbishment and actuator control cabinet replacement is planned.

As actuators are replaced, a source of spares will be generated that will minimise the obsolescence risk at other sites where spares and support from manufacturers are becoming increasingly difficult to obtain. The DST used to prioritise investment will be continually updated to reflect this evolving position, and hence the priority order for sites may change into the future.

Valves and Actuators Capex

During the current Price Control period, £5.9M has been spent on Valve and Valve Actuator replacement and major refurbishment schemes. In the forthcoming Price Control period, a significant increase in investment is planned amounting to some £17M over five years. Approximately two thirds (£12.1M) of this investment is required to address valve issues, with the rest targeted at addressing corrosion on valve actuator control cabinets.

The priority ranked list is being used to ‘bundle’ candidates of actuator types and their locations into efficient packages for replacement or refurbishment. These ‘bundles’ of candidates will then be developed into individual schemes for approval.

TPA Commentary

- TPA accepts the need for an ongoing valve replacement programme and that there is technical support for a ramping up of the valve replacement programme .

- However, in the absence of asset management evidence supporting expenditure at the level proposed by National Grid, TPA supports an increase from the £1.2M per annum in the current PCR period to £2.4M per annum in the next period, a total of £12M and a reduction of £5M from the level proposed by National Grid. The reduction also takes into account the forecast reduced utilization of compressor assets.

National Grid additional information

National Grid stands behind its original forecast of £17M

Revised TPA Commentary

TPA supports the principle of increasing the size of the valve and actuator replacement programme by a 100% increase in the level of expenditure.

It may be that in 5 years time National Grid is able to make a case to further increase this level as a result of asset management information from additional condition monitoring.

d) Other replacement at compressors and terminals

Some items from the FBPQ “Other capex’ spreadsheet are classed as Serviceability but are not in the above 4 categories, including things like:

‘Other Capex’

Category	2005/6-2006/7	2007/8 – 2011/12	Total
Bacton boiler	1.5	0	1.5
Cathodic protection	0	2.4	2.4
Inlet and exhaust stack	3.5	1.2	4.7
Alrewas diffuser	1.2	0	1.2
Batteries/UPS	0.2	2.8	3
Industrial metering	0	1.9	1.9
Gas pre-heating	0	1.9	1.9
Standby generator replacement	1.2	3.3	4.5
Spares	0	4.9	4.9
Cabs structure and ventilation	0	5.6	5.6
Recycle line	0	2.8	2.8
Total	**9.4**	**34.9**	**44.2**

Source: National Grid

TPA Commentary:

TPA believes that, in the absence of an asset management system that supports all this repex, it is difficult to substantiate any level of capex, whether that proposed by National Grid, higher or lower.

TPA believes the cab structure investment case is relatively weak and would support a reduction of 33% in this level (£1.87M) together with a reduction across the board of 10% (£3M) reflecting the absence of supporting business cases and forecast reductions due to reduced running hours

Total TPA supported level is £30M

National Grid additional information

In TPA's 'other capex' table, £11.1m (31.8%) of forecast capex is not directly related to compressor station reduced running hours. For example, cathodic protection, industrial metering, gas pre-heating and spares.

Revised TPA Commentary

TPA accepts that around 32% of the proposed capex is not related to running hours but believes that £30M remains an appropriate level of capex.

5.6.7 TPA General Commentary on Replacement

National Grid have said that there is not the level of asset management information available to fully justify condition based replacement at this stage but has put in place new policies and procedures to capture such information and make the condition based replacement case easier to make in subsequent price control reviews.

TPA notes that a significant replacement programme has been undertaken in the first 3 years of the current PCR and further work is scheduled for the period to 1 April 2007. At the end of the current PCR period, £72.3M will have been invested in replacing TO assets, mostly at compressor stations (in addition to telemetry replacement in the SO control). Going into the next PCR period, TPA accepts that there should be a compressor station assets replacement programme and believes the following principles are appropriate:

- [redacted]
- The compressor stations with the highest running hours are being modified as a result of the IPPC-NOX programme and as such should have investment at the time of the IPPC works in order to make them robust for the next 10 – 15 years
- [redacted]
- Compressor stations with low running hours but with prospect of some utilisation should not be decommissioned but efforts should be made to delay any replacement

expenditure until it is absolutely necessary. Compressors that operate off peak are not as critical as those that operate at times of system stress and this should also be taken into account.

- In addition, TPA has reported in the historic review that whilst reliability of compressor stations is good with high mean time between failures, it is not so good for compressor stations that have low running hours. TPA believes it is not necessarily efficient to maintain the option of using compressor assets 'because they are there' as in practice this operating philosophy will be expensive and reliability poor.
- [redacted]

[redacted]

- [redacted]
- [redacted]

[redacted]

- [redacted]
- [redacted]

[redacted]

Other benefits from surplus capacity:

- The additional linepack in the Northern NTS as a result of the pipeline uprating projects and the St Fergus – Aberdeen – Lochside pipeline should reduce the need for both Operating and Flow Margins.
- [redacted]
- All options should be explored in order to ensure that National Grid is able to focus on those compressor assets that are required for Licence and Safety Case drivers.

[redacted]

[redacted]

National Grid additional information

[redacted]

[redacted]

[redacted]

[redacted]

Revised TPA Commentary

Asset Redundancy

TPA has commented in Section 3 on the high St Fergus flow case in Section 3. Our view remains that flows from St Fergus will be significantly reduced once the Langeled pipeline is commissioned in September 2006. The saving in NTS entry charges of around £40M for 30 MCMD is highly significant and, we believe, represented part of the business case for landing Ormen Lange at Easington rather than St Fergus.

Hence, TPA maintains its view in relation to assets that are not likely to be required due to the decline in St Fergus flows.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

5.6.8 Other Major Infrastructure (forecast £6.5M in 05/6 – 06/7 and £52.7M in next PCR period)

Category	2005/6-2006/7	2007/8 – 2011/12	Total
Replacement of Humber crossing	0	28.6	28.6
Glenmavis LNG	6.5	24.1	30.6
Total	6.5	52.7	59.2

i) Replacement of the Humber crossing pipeline (£28.6M):

National Grid Business Case

As shown below, 2 pipelines cross the Humber; No1 feeder to Thornton Curtis and No9 feeder to Hatton. No1 feeder has been the subject of emergency measures due to tidal movements reducing both support and cover for the pipeline. There is no issue over No9 feeder, which crosses the Humber further upstream.

No1 feeder supplies an isolated 48bar system fed from the offshore West Sole field and Paull (when West Sole is not in operation). The tidal movements have scoured the river bottom and left sections of the pipeline uncovered and unsupported in the past. A temporary pipe link was installed at Thornton Curtis to supply the load from the No9 feeder as a contingency should the Humber crossing have to be closed down. Emergency measures have been employed to re-cover and support the pipeline to the satisfaction of the harbour master. However, the continuing action of the tide leaves the feeder exposed to future episodes of scouring and a more permanent solution is required. River bed surveys as recent as January 2006 have identified that this is still a problem, and the current length of unsupported pipeline is approaching the critical length under which vortex shedding phenomena may be induced leading to integrity implications. This may require further remedial action to resolve, such as the addition of further material to support the free span.

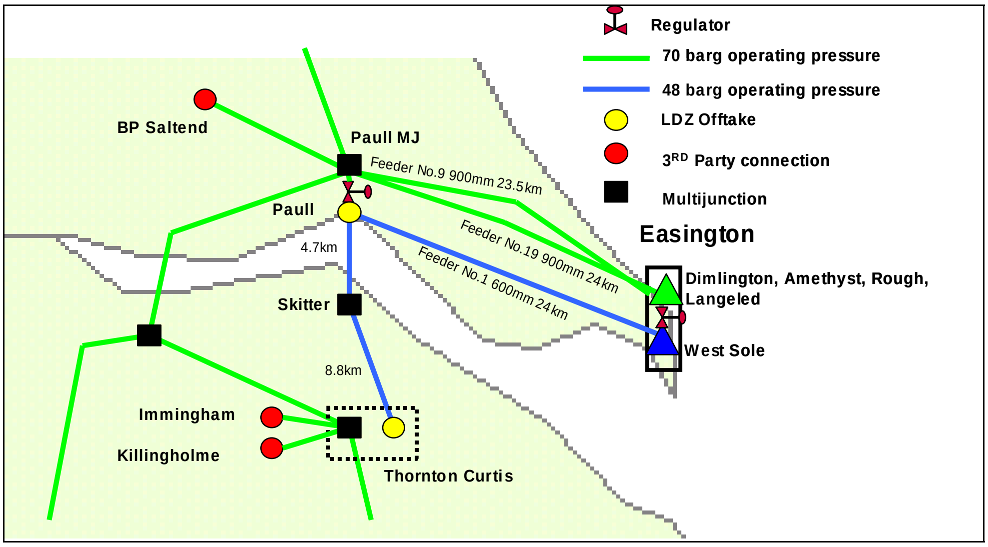
In the current Price Control period review a number of operational issues have been experienced on the Feeder No 1 pipeline where it crosses the Humber Estuary. Due to extreme riverbed conditions, with fast tidal flows in relatively shallow depths of water, this pipeline has experienced a number of occasions where the bed of the river has been scoured from under the pipeline, leaving it unsupported and vulnerable to third party damage such as anchors. Unsupported spans can be susceptible to Velocity Induced Vibration, which in extreme circumstances can dramatically reduce the fatigue life of the pipeline, and potentially result in failure in service unless remedial action is taken.

On a recent occasion, a 30m length of the pipeline was uncovered, and theoretical calculations identified that, if not reburied, the pipeline could fail due to fatigue in a matter of months. After extensive negotiations with statutory bodies (such as the Environmental Agency and the Harbour Master) a licence was granted to rebury the pipelines by the technique of “rock dumping” i.e. placing stones above the pipeline. A full integrity study was required to justify that the pipeline was fit for service, and this was demonstrated to the HSE. This remedial work was carried out at an operational cost of approximately £2m. A further exposure is currently being managed to keep the exposure within critical limits.

However, National Grid have indicated that the statutory bodies have stated that it is unlikely that another license would be granted for further rock dumping due to an increased European Environmental categorisation as a SPA (Special Protection Area). The stability of the river bed is now assessed as poor and the requirement for further remedial work on this crossing is seen as high.

National Grid have proposed £28.4m funding in the next PCR period to replace the existing pipeline across the Humber with a new pipeline using a tunnel.

Figure 36: Humber Crossing Scheme



Source: National Grid

TPA Commentary

- TPA believes that National Grid has demonstrated that there is a technical issue related to the existing No 1 feeder and that the measures taken to date have been reasonable. Given that a new link has been built at Thornton Curtis to the No1 feeder, it may well be that in the event of further difficulties with this pipeline crossing it should be abandoned.

- TPA believes that the Humber crossing replacement strategy should be considered as part of any future increase in Easington capacity (eg new southerly onshore route or if there is an offshore Easington to Theddlethorpe link?) If the crossing has to be maintained then capex of £5 – £28M may be required, subject to extent of the works. though it may be possible for no capex to be required at all if the temporary solution is effective.

National Grid additional information

National Grid acknowledge some uncertainty over the level of expenditure required for the Humber Crossing, but still believe that it is more likely to be in excess of the £5m allowed. As discussed and stated in our FBPQ, the Harbour Master has expressed a view that they are unlikely to allow us to undertake further rock dumping (at a cost of around £5m) and it is therefore more likely that a permanent tunnelling solution (at a cost of around £28m) would be required. In order to progress the issue, National Grid have estimated some probabilities of the various solutions, shown below:

- Probability of requiring remedial works (cost £5m) – 33%
- Probability of requiring tunnelling and replacement (cost £28m) – 67%

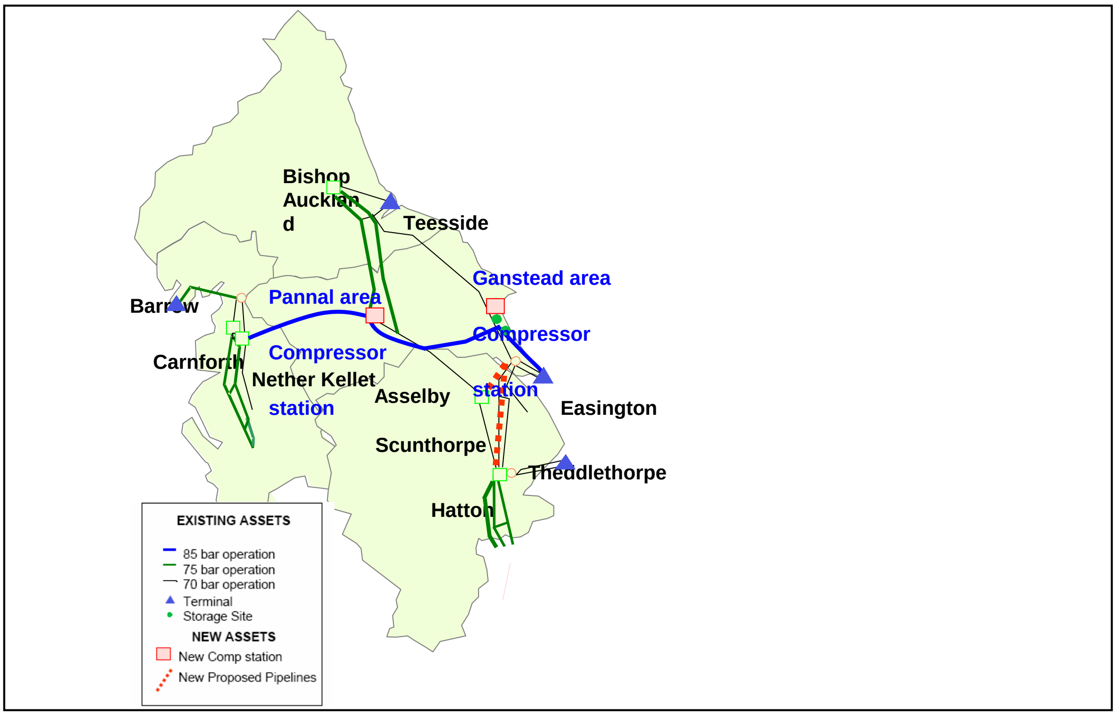
On this basis we would propose to take some risk on the possibility of requiring a most expensive (and in our view most likely solution) on a probability weighted allowance of approximately £20m.

Revised TPA Commentary

TPA believes that, in the event of a successful bids in the North West ([redacted]) in the September long term auctions, coupled with high Easington bids, it is likely that National Grid will have to build a new pipeline from Paull to Scunthorpe/Hatton as shown below.

TPA believes that this would be a more appropriate project than the Ganstead compressor to increase Easington capacity and would require a new crossing of the Humber. TPA believes the costs of decommissioning the existing No 1 feeder crossing should be treated as part of the capex for the new crossing

Figure 36 b: Alternative to Humber Crossing



Source: National Grid

ii) Glenmavis LNG (£24.1M in next PCR period)

Whilst part of National Grid's business which is currently outside RPI-X regulation, the investment at Glenmavis is required as part of National Grid's Safety Case.

This investment is subject to a separate review by TPA.

5.6.9 Other Non Load Related Expenditure

The following is taken from the FBPQ “Other capex’:

Non – load Related Expenditure

Category	**2005/6-2006/7**	**2007/8 - 2011/12**	**Total**
Remote cathodic protection monitoring	0	1.9	1.9
Gas generator ‘hot washing’ and air intake anti-icing	0.1	1	1.1
Gas quality metering at entry	8.6	19.6	28.2
Liquid monitoring at entry	1.1	2.3	3.4
Environmental standards	0	14.6	14.6
Minor works	1.2	2.4	3.6
ES – vehicles	0.8	1.5	2.3
ES - equipment	3.2	10	13.2
ES – PMC	1.0	1.3	2.3
ES – pipelines	0.6	0.4	1.0
ES - compressors	0.6	0.3	0.9
Sub total	**16.4**	**55.3**	**72.5**
Following not part of TPA Scope			
TO IS – MIMS Upgrade *	0	2.4	2.4
TO IS – Maximo upgrade	0	2	2
TO IS Capex - TSI	0.0	4.8	4.8
TO IS Capex - IS Infrastructure	1.0	1.8	2.8
TO IS Capex - Transformation	0.6	0.0	0.6
TO IS Capex - Shared Services	0.9	1.5	2.4
Procurement and Logistics Capital Expenditure	0.3	0.7	1.0
Misc Other Capex	3.4	1.1	1.0
Sub total	**6.2**	**14.3**	**17**
Total	**22.6**	**73**	**96.1**

2 scenarios for this – this is low figure, other is £3M higher

Source: National Grid HBPQ

Gas Quality Metering at Entry

TPA accepts the National Grid case for this investment and the level of capex proposed is reasonable.

Environmental Standards

National Grid argues that standards in its electricity business are higher than those on the NTS in relation to site drainage and the risk of leakage of diesel and other fuels. To that end, it argues that it could be necessary to replace or upgrade containment bunds, diesel/oil below ground supply pipework, interceptors, penstock shutoff valves and additional site drainage at compressor stations and terminals.

Similar schemes on the electricity transmission sub-station sites have approved capital investment for a risk-based programme addressing site-specific requirements. This programme has involved refurbishment, improvement or installation of pollution prevention measures including the replacement or upgrading of bunds and the installation of new oil separators and drainage systems to eliminate the escape of oil from site via drainage systems and to prevent future contamination. These schemes complement the current work dealing with potential risks from past contamination and have historically cost in the region of £0.5m per site.

In order to provide such a standard across the 26 compressor stations and 4 terminals on the gas transmission network, investment, in the region of £15m would be required.

TPA Commentary

- With respect to environmental standards, TPA accepts that there may be a case for preventative investment at certain sites based on detailed assessment, but does not believe that a case has been made for a general replacement programme at this stage. TPA suggests a range of £5M – 10M rather than the £14.6M proposed.

National Grid additional information

National Grid argue that they are likely to be required to improve the environmental standards on the NTS, in line with the improvements carried out at electricity sites in recent years. National Grid say that the application of environmental legislation on issues such as noise abatement, visual impact, emissions and discharges continue to tighten and they expect to be required to incur this expenditure. Ofgem proposed an allowance of £5m out of our FBPQ forecast of £15m. However, we acknowledge some uncertainty in the extent to which works will be required, and therefore believe that an allowance of between 70 and 80% (i.e. £10-12m) of our original forecast would provide a more appropriate sharing of risk on this issue.

Revised TPA Commentary

National Grid has not provided any evidence of new legislation or interpretation that supports this level of investment on the NTS to improve environmental standards. TPA accepts the principle of continuous improvement as required by ISO 14001 and believes a new fund of £5M is appropriate for this purpose, together with the £200M being invested in electrically driven compressors.

Together, this represents an enormous environmental contribution, probably a factor of 10 greater than anything carried out before on the NTS. Given no business case or demonstration of environmental necessity for investment in improved environmental standards, TPA does not believe an increase beyond £5M is justified.

[redacted]

5.6.11 TPA Summary Commentary on Non Load Related Capex

a) Non Load capex with no new system entry points in North West

A second version of the table has been produced with the impact of successful and significant bids for capacity in the Sept 2006 auctions [redacted]

Reference	Title	Description	Commentary
5.6.9.1	Extent of IPPC programme	[redacted]	[redacted]. Reduction of **£6.8M in 2006/07, and £44.8M in 2007/8 to 2011/12**
5.6.9.2	IPPC and Repex	IPPC programme to include compressor repex	When major capex is incurred re IPPC, TPA agrees that it is efficient to update the basic station [redacted]
5.6.9.3	Compressor Asset Management	Strategy to take into account changing utilisation	TPA believes that National Grid and Ofgem should agree a regulatory treatment for assets no longer required, [redacted] Potential saving of [**£15 -20M]** [redacted]
5.6.9.4	Repex - Protection and Control		TPA accepts the basic business case, but suggests a reduction of **£10M** [redacted]
5.6.9.5	Repex – gas generators and power turbines		TPA accepts the basic business case, but suggests a reduction of **£10M** [redacted]
5.6.9.5	Repex – Valves and Actuators		TPA accepts the basic business case, but suggests a reduction of **£5M** [redacted]
5.6.9.6	Repex - other		TPA accepts the basic business cases, suggests a reduction of **£4.9M** [redacted]
5.6.9.7	Replacement Humber crossing	£28M capex to replace a Humber crossing	National Grid have made a good case that the existing crossing may need significant capex or a replacement. TPA believes that a replacement of this crossing along is not an efficient outcome and would support an allowance of £5M to maintain the existing crossing as a medium term solution if necessary. This is a reduction of **£21M**
5.6.9.8	[redacted]	[redacted]	Reasonable case
5.6.9.9	Environmental standards	£15M proposed	TPA believes the FBPQ case is weak and suggests a range of between **£5M and £10M** for this activity

b) Non Load capex with new system entry points in North West

The version of the table below has been produced with the impact of successful and significant bids for capacity in the Sept 2006 auctions from new North West area system entry points (Fleetwood and Cheshire)

Reference	Title	Description	Commentary
5.6.9.1	Extent of IPPC programme	[redacted]	[redacted] Reduction of **£3.4M in 2006/07 and £22.4M in 2007/8 -2011/12**
5.6.9.2	IPPC and Repex	IPPC programme to include compressor repex	When major capex is incurred re IPPC, TPA agrees that it is efficient to update the basic station [redacted]
5.6.9.3	Compressor Asset Management	Strategy to take into account changing utilisation	TPA believes that National Grid and Ofgem should agree a regulatory treatment for assets no longer required, [redacted]. Potential saving of[**£15 -20M** [redacted]
5.6.9.4	Repex - Protection and Control		TPA accepts the basic business case, but suggests a reduction of **£6.4M** due to lower compressor running hours [redacted]
5.6.9.5	Repex – gas generators and power turbines		TPA accepts the basic business case, but suggests a reduction of **£9.1M** [redacted]
5.6.9.5	Repex – Valves and Actuators		TPA accepts the basic business case, but suggests a reduction of **£5M** [redacted]
5.6.9.6	Repex - other		TPA accepts the basic business cases, suggests a reduction of **£4.9M** [redacted]
5.6.9.7	Replacement Humber crossing	£28M capex to replace a Humber crossing	Not required as new crossing on new pipeline likely to be required, reduction of £28M TPA believes the costs of decommissioning the existing No 1 feeder crossing should be treated as part of the capex for the new crossing
5.6.9.8	[redacted]	[redacted]	Reasonable case
5.6.9.9	Environmental standards	£15M proposed	TPA believes the FBPQ case is weak and suggests a range of between **£5M and £10M** for this activity

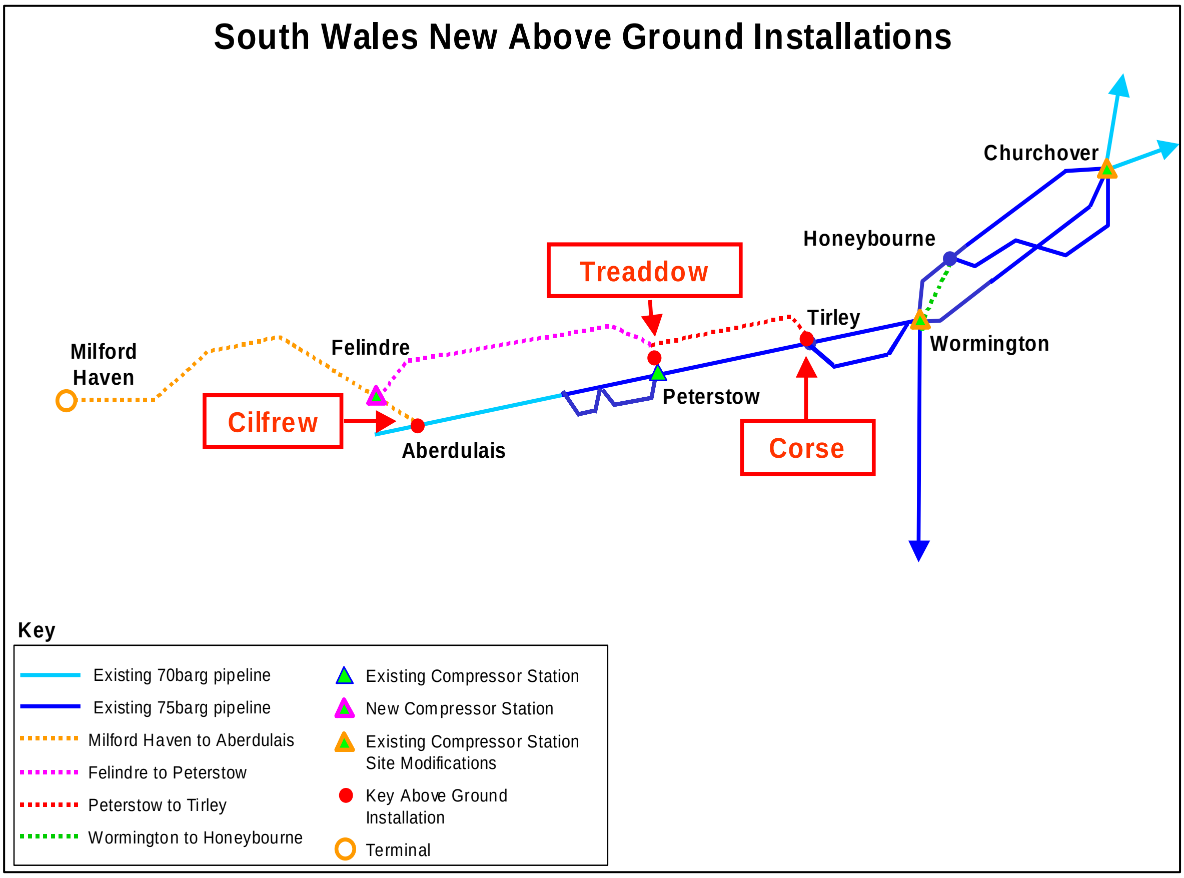
5.7 Efficient Costs to deliver the programme

5.7.1 Review of Unit Costs in FBPQ Compared to HBPQ

In the HBPQ, TPA reviewed the delivery strategy for new pipelines and compressor stations (Section 6.2) and the unit costs (Section 6.4). TPA's conclusions were that the delivery strategy was generally efficient and the unit costs, for pipelines and compressors, compared generally favourably with projects in the 1995 – 2002 period.

In this report, after discussion with Ofgem, it was decided that TPA would analyse the Milford Haven related NTS Expansion projects (the comparable section in TPA's HBPQ Report is 6.3 where TPA looked at delivery strategy for a number of St Fergus projects). The projects are shown below.

Figure 3



Source: National Grid

In relation to the Milford Haven projects, TPA focused on three questions:

- Is the **contracting strategy** for these projects efficient?
- Are the basic FBPQ **unit costs** (compared to HBPQ period) efficient (for pipelines and compressors) and what are the reasons for any increases?
- Are the **unit cost increases** forecast by National Grid from the level in the FBPQ to April 2006 justified (for pipelines and compressors)?

TPA's methodology to answer these questions was as follows:

- Visit the Milford Haven to Felindre pipeline project and discussions with key project staff employed by National Grid and the main works contractor.
- Submit written questions to National Grid.
- Review of detailed 1200 mm pipeline unit costs for all FBPQ projects (Easington and Bacton related too) and comparing these both to HBPQ projects and to each other.

TPA has not attempted to benchmark these project costs with the costs in other countries as this would be a difficult exercise given that a significant proportion of pipeline costs relate to local terrain and environmental conditions. However, TPA has benchmarked the FBPQ projects against the costs incurred for 1200 mm diameter pipelines in the HBPQ period 2002-2005.

5.7.2 Contracting Strategy

[redacted]

[redacted]

[redacted]

[redacted]

- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Source: National Grid/TPA Analysis

[redacted]

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[redacted]

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[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Source: TPA Analysis

[redacted]

	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]		[redacted]

Source: TPA Analysis

[redacted]

Source: TPA Analysis

[redacted]

	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]		[redacted]

Source: TPA Analysis

[redacted]

Source: TPA Analysis

[redacted]

	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]		[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]		[redacted]

TPA Commentary

[redacted]

[redacted]

[redacted]

5.7.3. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

5. 8 Executive Summary

5.8.1 TPA Commentary

Capex area (figs for 7 year period)	TPA Commentary
Baseline (Easington and Bacton) - £357M	Good business case
Baseline – new entry points [redacted] – approx £584M	Good business case, unit costs very high but process for delivery is generally not inefficient
Increased capacity above Baseline – [redacted] - £81M	Good business case, unit costs very high but process for delivery is generally not inefficient
Exit [redacted]	Good business case, unit costs very high but process for delivery is generally not inefficient
[redacted]	[redacted]
SW Demand - £170M	TPA recommends that National Grid and Ofgem use the South West DN load growth/NTS capacity issue in order to inform the shipper community in relation to load growth (higher gas prices), Exit Reforms, Flow Margin and Constrained LNG at Avonmouth with the prize being that none of the forecast SW DN projects are built. TPA believes that Ofgem should consider an SO incentive on National Grid in order to achieve this ([redacted]). Given the uncertainty related to gas prices and the above factors, TPA believes that as a central scenario, the capex required for SW DN load growth should be reduced by **£68.3M** (capex in last 2 years of the next PCR period)
[redacted]	TPA does not believe that National Grid has demonstrated a business case for this investment ([redacted])
[redacted]	[redacted]
IPPC - £253M *	[redacted]
Serviceability - £145M *	Reduction of **£29.5M** plus any savings due to relocated assets (**£7.5- 10M)**
Humber crossing - £28M	Possible saving of **£0 -23M**
[redacted]	Seems reasonable (TP4180 to be reviewed)
Other non load related -	Environmental standards case is weak in FBPQ narrative – possible - **£5 – 10M** reduction

** additional capex likely to be required in these areas in the event of successful entry capacity bids in the September 06 long term auctions* [redacted]

5.8.2 Financial Summary

Area	**Potential increase/reduction Compared to FBPQ (2007/8-2011/12) £M**	
National Grid FBPQ	1448	1448
National Grid FBPQ – Projects Not Yet Approved by National Grid	758	758
	Lowest capex	**Highest capex**
National Grid revised capex forecasts for approved pipeline and Milford Haven compressor projects **Note 1 and Note 2**	+218.1	+218.1
Exit – [redacted]	-157	-157
Exit – SW load growth	-137	-68.3
[redacted]	-31.8	-31.8
IPPC – extent of programme	-51.6	-51.6
IPPC – [redacted]	-10	-7.5
Asset repex – extent of programme	-29.5	-29.5
Asset repex – [redacted]	-10	-7.5
Other major capex	-23	0
Other non load related (Enviro Standards)	-10	-5
Total TPA reduction	**-459.9**	**-358.2**
TPA reduction less National Grid increase – ie TPA net reduction	**-241.8**	**-140.1**
Total TPA net reduction as % of National Grid FBPQ	16.7%	9.7%
Total TPA reduction as % of National Grid FBPQ – Not Yet Approved	31.9%	18.5%

[redacted]

[redacted]

Notes

[redacted]

[redacted]

Source: National Grid

[redacted]

[redacted]

[redacted]

[redacted]