JOINT GAS CAPACITY STATEMENT 2012

Commission for Energy Regulation

An Coimisiún um Rialáil Fuinnimh

Utility Regulator

ELECTRICITY GAS WATER

Contents

Foreword

Background Information

The 2012 Joint Gas Capacity Statement (JGCS) presents an assessment of the ability of the all-island transmission network to meet forecast gas demand and potential supply scenarios over the next ten years (2011/12 to 2020/21). The network analysis presented in the JGCS has been principally prepared by Bord Gáis Networks (BGN) with input from the Transmission System Operators (TSOs) in each jurisdiction.[1]

The 2012 JGCS is the fourth annual report produced by the Commission for Energy Regulation and the Northern Ireland Authority for Utility Regulation as part of the Common Arrangements for Gas (CAG) project under the All-island Energy Market Development Framework. The Commission for Energy Regulation ('the CER') is required to publish this analysis, including a 7 year demand projection, under section 19 of the Gas (Interim) (Regulation) Act, 2002, as amended by the European Communities (Security of Natural Gas Supply) Regulations 2007 (S.I. No. 697 of 2007). The TSOs in Northern Ireland (NI) are obliged through their codes and licences to produce an annual pressure report/network forecast for presentation to the Northern Ireland Authority for Utility Regulation ('the Utility Regulator').

In April 2008, the CER and the Utility Regulator jointly published a Memorandum of Understanding on the development of the CAG project.[2] Under CAG, the CER and the Utility Regulator ('the Regulatory Authorities') aim to facilitate the operation of the natural gas market in Ireland and Northern Ireland on an all-island basis. As part of this objective, both Regulatory Authorities are committed to a single approach to security of supply on the island which involves the production of a joint report on the island's expected gas supply and demand.

The JGCS is the fourth such report to have been prepared on an all-island basis. In previous years the Utility Regulator published an annual Pressure Report and the CER published its annual Gas Capacity Statement. Both publications presented separate gas supply and demand scenarios and separate assessments for the transmissions systems in each jurisdiction. The principal divergence from previous national reporting is that all flows are considered from the current and future entry points in Ireland and Northern Ireland to an integrated all-island system.

Since 2010 the analysis contained within the JGCS has changed to include analysis over a ten year period. This change was undertaken in order to align the analysis of Ireland and Northern Ireland with that of the European 10-Year Network Development Plan produced by the European Network of Transmission System Operators for Gas every two years under EC Regulation N° 715 of 2009. The 2012 JGCS therefore includes updated analysis and modelling of the impact of forecast gas supply and demand on the island's transmission systems for the period 2011/12 to 2020/21.

Gas Supply Scenarios

The 2012 JGCS examines four potential supply scenarios up to 2021. In all scenarios it is assumed that Corrib will come on stream in 2015/2016. The four scenarios are as follows:

Scenario 1	Scenario 2	Scenario 3	Scenario 4
Corrib From 2015/16	Corrib From 2015/16	Corrib From 2015/16	Corrib From 2015/16
Inch Until 2016/17	Inch All Years	Inch All Years	Inch All Years
Moffat	Moffat	Larne 2017/18	Shannon 2017/18
		Moffat	Moffat

[1] The following parties were involved in the preparation of this analysis: Bord Gáis Networks on behalf of Gaslink; Premier Transmission Limited & Belfast Gas Transmission Limited (both owned by Mutual Energy Limited); Bord Gáis Éireann (UK) Limited working with Bord Gáis Networks.

[2] The Memorandum of Understanding is available on both the websites of the CER and the Utility Regulator.

The 2012 JGCS diverges from the analysis undertaken in previous years in terms of the principal supply sources under consideration. The scenarios in this year's Statement are more limited in terms of the flows taken as being available from the Inch Entry Point. The RAs have examined the possibility of Inch ceasing in 2016/17 in one scenario. In all other scenarios Inch has been examined as being available.

A further difference in the analysis undertaken, compared to previous years, is the available pressure levels at the Moffat Entry Point and assumptions around the Beattock Compressor station. This year's modelling has assumed a pressure of 47 barg from the NTS at Moffat until 2014/15 (inclusive) and a lower pressure of 45 barg from 2015/16. The modelling has also assumed a lower discharge pressure of the Beattock compressor station of 76.6 barg for all years modelled (compared to 85 barg in previous years). The reasoning for the change in assumptions is explained further in section 5.3.2.

The system modelling undertaken by BGN also takes into account flows from GB through the Scotland to Northern Ireland Pipeline (SNIP) and the two BGE subsea Interconnectors, as well as on flows via the South North Pipeline (SNP). The potential for reverse flows through the Scotland to Northern Ireland Pipeline (SNIP) to Ireland are also examined.

Taking into account the four supply scenarios, and in consideration of the continuing reliance on Moffat, network modelling carried out by BGN demonstrates that capacity limits will be approached in 2014/2015, 2018/2019, and 2020/2021. Modelling results also indicate that further delays to Corrib production will result in capacity limits being reached at the Moffat entry point in 2015/2016 and during any subsequent years of delay.

Gas Demand

As regards Irish gas demand ROI annual gas demand contracted by 4.6% in 2010/11 compared with the previous gas year. This decrease in gas demand can be attributed to an increase in electricity production from renewables, primarily wind coupled with an overall decrease in electricity demand over the period. This followed a period of increased power sector gas demand as a result of lower wind generation, lower gas prices and severely cold weather.

Overall peak day gas demand fell by 14.1% in 2010/11 but has increased by 3.8% per annum since 2004/05. It is important to note that since 2004/05 peak day demand has been driven primarily by the changing electricity generation portfolio which has moved towards gas fired generation. In 2011/12 peak day demand was driven by power generation which accounted for 55.4% of total gas demand. The non power sector saw a reduction in demand which was primarily due to the milder winter period than the previous 2 years.

Total annual gas demand in Northern Ireland has increased by 2.98% from 2009/10 to 2010/11. This increase was caused largely by the unavailability of the Moyle interconnector which resulted in lower imports and therefore increased use of gas fired power stations in Northern Ireland.

However in more recent years total annual gas demand has fallen. This overall decrease in demand from 2006/2007 until 2009/10 has occurred as a result of the economic recession, power generation dispatch moving from Northern Ireland to the Republic of Ireland and an increase in renewable energy sources.

The distribution sector within Northern Ireland continues to grow with an increase of 5.81% in annual demand from 2009/10 to 2010/11. This represents steady growth within the Phoenix Natural Gas and Firmus distribution systems.

In terms of the gas demand forecast, three gas demands were devised for the 2012 JGCS (minimum summer day, average winter peak and severe 1-in-50 winter peak). The separate demands for the two jurisdictions were combined to produce a single total for each of the three demand scenarios modelled. For the ROI demand scenario the different sectors of the economy were modelled as well as future economic growth rates, new housing construction, electricity demand and fuel prices,

For Northern Ireland the demand forecast was determined from the latest demand forecasts from the distribution companies and power generation sector.

Overall, as electricity generation accounts for the majority of gas demand it is expected that a decrease in electricity production will result in a decrease in overall gas demand. Despite overall lower production it is expected that gas demand will rise from 2012/13 due to a recovery of electricity demand, an increase in gas generation as an overall percentage of production as HFO plants are retired, an increase in carbon prices and the potential for lower imports from BETTA due to the Large Combustion Plant Directive. I/C demand is expected to match GDP growth at a rate of 80%. It is expected that growth in 2012/13 will be moderate and steady for much of the period thereafter.

Residential growth rates will be impacted by both the number of new connections and the government's planned energy efficiency initiatives. Residential connections are expected to continue to decline before increasing towards the end of the analysis period.

Overall, in ROI it is expected that gas demand will increase by 2.9% p.a. between 2011/12 to 2020/21. This is a slight increase on last year's report due to an increase in I/C and residential demand.

The overall gas demand in Northern Ireland is forecast to grow relatively slowly by 1.62% over the period modelled. The gas demand from the power sector is forecast to remain stable with steady growth predicted in the distribution sector where an annual growth rate of 2.86% is expected. This is largely dependent upon new connections within both the domestic and industrial and commercial sector.

The Regulatory Authorities would like to thank all those who contributed to the development of this Joint Gas Capacity Statement, especially Bord Gáis Networks, Mutual Energy[3] and Gaslink. The Regulatory Authorities also acknowledge the assistance of many other parties in producing this Statement, including shippers, gas producers, power producers and large consumers, interested parties and industry observers.

We hope you will find the information it provides helpful.

[3] Mutual Energy Limited is the ultimate holding company for Premier Transmission Limited and Belfast Gas Transmission Limited, the owners and operators of the Scotland to Northern Ireland Pipeline and the Belfast Gas Transmission Pipeline respectively.

1 Introduction

1.1 Background Information

The JGCS 2012 examines forecasts of customer demand for natural gas, the relevant sources of supply and the capacity of the gas transmission system on the island for the period 2011/12 to 2020/21. The JGCS therefore provides up to date information to interested parties on the ability of the all-island gas transmission network to meet forecast gas demand and potential supply scenarios.

The CER is obliged under Section 19 of the Gas (Interim) (Regulation) Act, 2002, as amended by the European Communities (Security of Natural Gas Supply) Regulations 2007 (S.I. No. 697 of 2007), to monitor and report on the security of supply of natural gas in Ireland. As part of this requirement, a gas capacity statement is to be published each year and submitted to the European Commission in accordance with Article 5 of EU Directive 2009/73/EC.

The principal objective of the Utility Regulator, as set out in the Energy (Northern Ireland) Order, is to promote the development and maintenance of an efficient, economic and co-ordinated gas industry in Northern Ireland. The JGCS supports this objective and provides the gas industry in Northern Ireland with an annual assessment of the ability of the transmission network to meet future requirements on the system. Prior to the JGCS, the Utility Regulator and NI TSOs published an annual Pressure Report which assessed the capability of the transmission network in Northern Ireland only.

The transmission system operators in Northern Ireland are obliged in their respective network codes and licences to jointly produce a pressure report based upon network analysis of relevant supply and demand scenarios. The publication of the JGCS meets these requirements.

While the JGCS fulfils the relevant statutory and licence requirements in both jurisdictions, the Regulatory Authorities are conscious of the importance of the JGCS in developing a harmonised approach towards security of supply under the CAG project. The Regulatory Authorities also consider that the analysis of the transmission systems on an all-island basis will facilitate more efficient investment in gas infrastructure in the future.

1.2 Overview of Supply Demand and Analysis

The Regulatory Authorities and TSOs jointly developed future demand and supply forecasts based on a number of key assumptions and inputs.

For the demand forecast, the Regulatory Authorities specified the inputs and assumptions relating to:

- economic growth forecasts provided by the Economic and Social Research Institute (ESRI), which are used to forecast industrial and commercial customers' requirements for gas.
- gas connection figures for 2009 and 2010 from BGN and projected new housing constructions based upon data from the ESRI and the Department of the Environment, which were used to forecast residential demand for gas.
- sources for fuel and commodity prices as required inputs for a merit order electricity model run by BGN. Prevailing spot and forward prices for the UK National Balancing Point (NBP) have been used.[4]
- the gas-fired power stations assumed to be connected to the network in Ireland and Northern Ireland during the forecast period as provided by EirGrid & SONI.
- forecast electricity demand on the island in light of peak electricity demand in December 2010 and modelling results of EirGrid and SONI as noted in their Median Base Scenario.[5]
- assessments of the likely impact on residential gas consumption of measures to improve energy efficiency based in part upon initiatives set out in the Irish Government's *National Energy Efficiency Action Plan 2009–20* (NEEAP).[6]

[4] It should be noted that fuel-price variations, which may create some additional uncertainty, have been taken into account as part of BGN's power generation forecasting model.
[5] EirGrid & SONI, *All-island Generation Capacity Statement 2012-2021* (December 2011).

The supply and demand forecast is compiled from a number of data sources in addition to consultation with existing and potential market participants. The data sources include:

- a questionnaire from the Regulatory Authorities seeking information from industry participants related to current and projected levels of supply and demand;
- general economic and industry forecasts. In particular, the JGCS used information provided from the ESRI about macro-economic factors and changes in the housing market;
- the number of new load connection enquiries and the current year's operating experience as provided by BGN;.
- NI power and distribution demand forecasts provided by the distribution companies and power stations;
- The SONI & EirGrid *All Island Generation Capacity Statement 2012-2021*[7].

As regards Irish gas demand, key sources utilised in the preparation by Gaslink of this year's *Network Development Statement* (e.g. GDP rate, energy efficiency, electricity demand) have also been used for this year's JGCS.

In the preparation of the JGCS, the Regulatory Authorities received information regarding the timing/duration of certain developments. Based on this information, the following start/end dates were utilised as part of BGN's network modelling.

- Gas from the Corrib field was taken as being available in 2015.
- PSE Kinsale have indicated that the existing storage operations may cease in 2013/14, thereafter a decommissioning period will begin during which injection operations would cease and the cushion gas will be drawn down from the wells in the years from 2013/14 to 2016/17. This is examined in one scenario. In all other scenarios Inch is examined as being available for all years.
- Gas from a salt cavity storage at Larne was taken as coming online in 2017.
- Liquefied Natural Gas (LNG) becoming available at the Shannon LNG terminal at Ballylongford Co. Kerry in 2017.

The potential timings of these projects have been used to develop four supply scenarios.

1.2.1 Supply Scenarios

The approach taken to address uncertainties associated with the timing of new indigenous gas sources or in the rates of demand growth was to model four supply scenarios and to conduct a full network analysis to assess the transmission network on the island over the subsequent ten years (2011/12 to 2020/21).

The four main supply scenarios discussed in the 2012 JGCS are set out below:

Scenario 1	Scenario 2	Scenario 3	Scenario 4
Corrib From 2015/16	Corrib From 2015/16	Corrib From 2015/16	Corrib From 2015/16
Inch Until 2016/17	Inch All Years	Inch All Years	Inch All Years
Moffat	Moffat	Larne	Shannon

[6] Department of Communications, Energy & Natural Resources, *Maximising Ireland's Energy Efficiency - The National Energy Efficiency Action Plan 2009 - 2020* (May 2009).
[7] See SONI EirGrid *All Island Generation Capacity Statement* 2012-2021

		2017/18	2017/18
		Moffat	Moffat

The aim of such scenario analysis is to examine whether the system is adequate to cope with a reasonable expectation of demand over the next ten years. The assumptions related to demand growth are presented in Section 3 and specific results of the analysis are described in detail in Section 5.

The order of despatch for the various sources of supply is shown with indigenous production being despatched first followed by indigenous storage. Supplies from Moffat meet the projected balance.

The Regulatory Authorities note that the despatch of the various sources of supply for the four scenarios has been ordered so as to focus on the impact of flows from particular infrastructure project(s) on the all-island system. It should be emphasised that these orders have been applied solely for demand/supply modelling and network analysis purposes. The actual orders in which supplies will be despatched will be determined by shipper nominations and the commercial arrangements between shippers and producers/suppliers at the various Entry Points.

The CER and the Utility Regulator have engaged with developers in ROI and NI on the status of various gas supply projects. Where sufficient information is available, potential supply sources have been modelled with the permission of the relevant developers. The Regulatory Authorities have sought not to take a view on the commercial viability of existing or proposed projects. The inclusion of data for these projects as part of the modelling for the JGCS is based on information provided by producers/storage operators and is not intended to refer to the likelihood of these infrastructure projects being progressed.

1.2.2 Network Modelling

Hydraulic models of the combined ROI and NI transmission systems, which are utilised to analyse the four supply scenarios, simulate a 3-day 24 hour demand cycle of the all-island transmission system. Modelling was carried out using “PipelineStudio®” simulation software which was configured to analyse the transient 24 hour demand cycle over a minimum period of three days to obtain consistent steady results.

Information relating to measured daily pressures and profiles of consumption have been used to form this model. This model was subsequently run for the ten years of the JGCS from 2011/12 – 2020/21 inclusive and focused on insufficient capacity and on any resulting increases or decreases in operating pressures outside of acceptable parameters.

The hydraulic models for 1-in-50 demand flows were re-calibrated by BGN in light of the record flows on the all-island’s transmission system which occurred on the 8th of December 2010. The network modelling assumes that the physical separation of the two jurisdictions’ transmission networks (referred to as ‘CAG Closed’) can be removed and that the necessary operational and commercial requirements are in place as part of the CAG project to facilitate the potential transported of surplus gas from NI into ROI and from ROI into NI as required (referred to as ‘CAG Open’).

In relation to ROI demand, the individual market sectors have been combined to form annual demand projections. As regards Northern Ireland, the demand projections are based upon a power and non power division. Corresponding peak-day demands were calculated for 1-in-50 winter peak-day conditions.

In order to assess the system on days of different demand patterns, three sample demand type day scenarios were analysed for each supply scenario over the 10 year period from 2011/12 – 2020/21 inclusive as part of the modelling: 1-in-50 year winter peak day, average year winter peak day and average year summer minimum. The demand profiles adopted a single gas demand forecast by combining the forecasts for both Ireland and Northern Ireland.

Additionally for storage, these demand type days represent the best case scenario regarding maximum possible withdrawal rates on peak days and maximum possible injection rates on summer minimum days, assuming the various proposed storage facilities included in the analysis operate on a seasonal basis, i.e. injecting gas during the summer months and withdrawing gas during the winter months.

The Regulatory Authorities have jointly prepared the inputs to the demand forecasting model together with the TSOs in each jurisdiction and are satisfied that the most up to date information has been utilised to generate the appropriate gas demand forecasts. Having examined the modelling output of the various supply scenarios, discussions were also held between the Regulatory Authorities and the TSOs as part of the drafting of the JGCS in order to assess possible ‘pinch points’.

As part of the development of the CAG project, analysis is also being undertaken by the TSOs on the capability of the transmission networks, subject to some modifications, to deliver services on an all island basis under certain scenarios. This network analysis is ongoing in parallel with the JGCS at the request of the RAs.

1.3 Report Structure

The remainder of the JGCS is set out as follows:

Section 2 describes the transmission network in Ireland and Northern Ireland.

Section 3 provides information on historic and forecast gas demand for Ireland and Northern Ireland and in relation to the individual market sectors.

Section 4 discusses the current sources of gas supply on the island, the potential development of new sources, and the requirement for gas imports.

Section 5 describes the network simulation and supply-demand scenarios.

Section 6 sets out the modelling analysis results

Section 7 Sets out the conclusions and recommendations of the Regulatory Authorities arising from the network analysis noted

Appendix 1: Peak Day Demand Forecasts

Appendix 2: System Modelling Approach

Appendix 3: CAG System Configuration

Appendix 4: Energy Efficiency Assumptions

2 Transmission network

2.1 Overview of the gas transmission system in Ireland and Northern Ireland

Gas supply in Ireland is delivered via a network of c. 13,150km of pipelines. The integrated supply network is sub-divided into 2,380km of high pressure sub-sea and cross-country transmission pipe and in excess of 10,750km of lower pressure distribution pipe connecting customers to the system.

Figure 2.1: The existing transmission network in Ireland, Northern Ireland and onshore Scotland

Source: BGN

Pipeline Key

Existing Pipelines *(BGÉ/BGÉ UK)*	
S. N. I. P. *(PTL)* & BGTP (*BGTL*)	
Pipelines Planned/Under Construction	

The system conveys gas from two Entry Points at Inch in County Cork and Moffat in western Scotland to directly connected customers and distribution networks throughout Ireland, as well as to connected systems at exit points at Twynholm in Scotland (the Scotland to Northern Ireland Pipeline, 'SNIP'), and to the Isle of Man (IOM). The Moffat Entry Point, located onshore in Scotland, connects the Irish natural gas transmission system to the National Grid system in GB, so that gas can be imported via the GB pipeline system to Ireland. The Inch Entry Point connects the Kinsale and Seven Heads gas fields and the Kinsale storage facility to the onshore network. The Irish system has three compressor stations: Beattock and Brighouse Bay in southwest Scotland, and Midleton in Co. Cork.

The Northern Ireland transmission network is made up of 438km of high pressure pipeline which connects the on-land system in Scotland with the two power stations in NI at Ballylumford and Coolkeeragh. Gas initially arrived in NI in 1996 with the completion of the SNIP and pipelines of Belfast Gas Transmission Limited (BGTL) which delivered gas to the Ballylumford power station and to the Phoenix distribution network in Greater Belfast. The North West (NWP) and South North (SNP) pipelines were completed in 2004 and 2006 respectively allowing the development of distribution networks in the ten towns along the pipelines which are owned and operated by Firmus energy. The SNP also connects the NI system with the Irish system. Currently, all NI demand is supplied via the SNIP.

2.2 Scottish onshore system and Subsea system

The Moffat Entry Point connects the Irish natural gas system to that belonging to National Grid in GB, and allows for the importation of GB gas to Ireland and Northern Ireland. From the connection with the National Grid system at Moffat, the Scottish onshore system consists of a compressor station at Beattock, which is connected to Brighouse Bay by two pipelines from Beattock to Cluden and a single pipeline from Cluden to Brighouse Bay, all capable of operating at 85barg. A second compressor station at Brighouse Bay compresses the imported gas into the two sub-sea interconnectors which can operate at pressures in excess of 140barg if required. Before reaching the Brighouse compressor station, an offtake station at Twynholm supplies gas to Northern Ireland via the SNIP. The SNIP pipeline has a maximum operating pressure of 75barg, although there is a minimum guaranteed supply pressure into this system which is currently 56barg.

From Brighouse Bay there are two pipelines connecting Ireland to GB. Interconnector 1 (IC1), which consists of 600mm pipe, has been in operation since 1993. Interconnector 2 (IC2), which was constructed using 750mm pipe, was completed in 2002 and has been operational since January 2003. There is a sub-sea spur connection to the Isle of Man from IC2 which first supplied gas to the island in May 2003. IC1 and IC2 are connected to the onshore Irish system north of Dublin at Loughshinny and Gormanston respectively.

2.3 Onshore Transmission System in Ireland

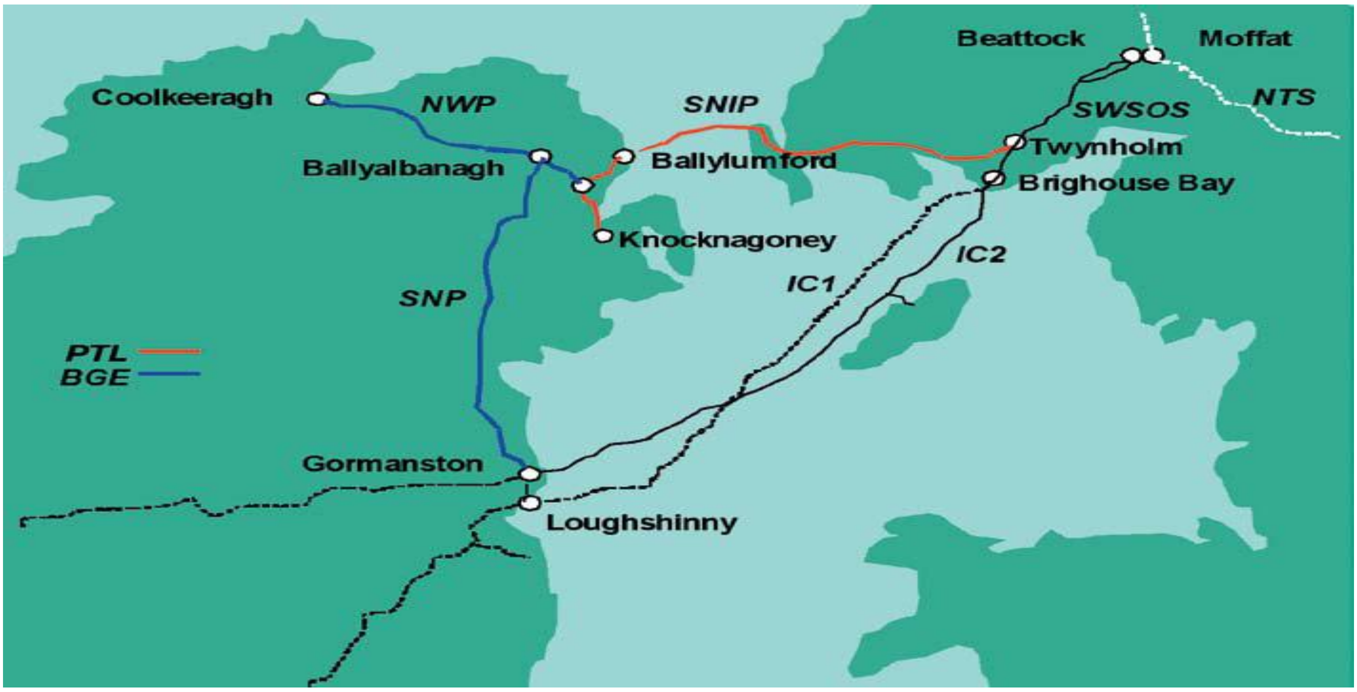
The onshore transmission system has been developed over a 34-year period and conveys gas from two Entry Points to customers supplied directly from the system and the distribution network throughout Ireland. The original part of the system was built in 1978 to supply the Cork area from the Kinsale Head gas field. The connecting subsea pipeline is owned and operated by PSE Kinsale Energy Ltd (formerly known as Marathon Oil Ireland Limited). The main Cork to Dublin trunk pipeline was built in 1982, with pipeline spurs constructed to intermediate locations. The onshore Irish system was expanded in 2002/3 by the completion of the Pipeline to the West which has a design pressure of 85barg. This created a ring main pipeline system which connects eastern, western and southern regions. The ring main pipeline contributes to continuity of supply by allowing customers to be supplied from an alternative direction, providing a more secure gas transportation system. It also provides some flexibility to cope with increased flows from the West coast of Ireland to demand centres in the East. The Inch entry terminal is connected directly to the Cork system and the only compressor station in Ireland at Midleton to boost the gas flow from Inch.

The Mayo to Galway pipeline links the Corrib gas field to the Irish market. The 149 km of 650mm diameter pipeline from Mayo to Galway connecting the onshore terminal in Bellanaboy Co. Mayo, into the Pipeline to the West at Craughwell in Co. Galway has been completed. The Mayo-Galway pipeline is fully operational and the majority of the Mayo towns from the New Towns Review (Phase I) are receiving gas.

2.4 The Northern Ireland Gas Transmission System

The Scotland to Northern Ireland 600mm pipeline (SNIP) connects to the BGÉ system at Twynholm in Scotland and has a maximum operating pressure of 75 barg. The pipeline is 135 km long and runs towards the coast near Stranraer and crosses the Irish Sea to terminate at Ballylumford Power Station, Island Magee. The SNIP is owned and operated by PTL.

Figure 2.2: The transmission network in Northern Ireland



The Belfast Gas Transmission Pipeline (BGTP) comprises a further 35kms of 600mm pipeline with a maximum operating pressure of 75 Barg and runs from Ballylumford via Carrickfergus to Belfast, where it supplies the Greater Belfast demand. From Carrickfergus 112km of 450mm pipeline extends to supply the power station at Coolkeeragh. This pipeline, the North-West Pipeline (NWP), is owned and operated by BGÉ (UK) Ltd. The Firmus energy distribution network also connects several towns to the pipeline.

A 450mm pipeline connecting the Interconnector System to the North-West Pipeline was built in 2006. This pipeline, called the South-North Pipeline (SNP), is 156kms long and extends from the IC2 landfall at Gormanston, Co. Meath in Ireland to Ballyalbanagh on the North - West Pipeline, approximately 12km west of the Carrickfergus AGI. This pipeline facilitates supplies to towns and industries in the corridor from Newry to Belfast (also being developed by Firmus energy) and in the longer term will be able to support the SNIP pipeline in meeting increased demand levels in Northern Ireland. The SNP was developed by BGÉ (UK) Ltd and is included in the NI postalised transmission system.

2.5 Planning the Transmission System

In July 2008 Gaslink was formally established as the independent Transmission and Distribution System Operator, and BGÉ as the System Owner of the BGÉ transportation system under the European Communities (Internal Market in Natural Gas) (BGÉ) Regulations 2005, S.I. No. 760 of 2005. BGN carries out the day-to-day operations and maintenance of the system under the direction of Gaslink. The Operating Agreement sets out the relationship between System Operator and System Owner. EU Directive 2009/73/EC, as part of the Third Energy Package, contains unbundling provisions designed to separate the supply and networks activities of Vertically Integrated Utilities (VIUs), such as BGE, in order to facilitate non-discriminatory access to gas transmission networks. The Directive outlines a number of models by which Member States can achieve compliance with the unbundling requirements. Originally the ITO model (Independent Transmission Operator) model in respect of BGE was chosen. However, subsequently a government decision was made to sell the energy assets of BGE. Consequently it is anticipated that a submission for certification for a fully unbundled TSO will be submitted by BGE.

Under Condition 11 of Gaslink's Transmission System Operator Licence, Gaslink is required to produce a long term development statement for submission to the Commission each year. Information compiled for the Network Development Statement has been utilised in the preparation of this year's JGCS and also covers the period 20011/12 to 2020/21.

Northern Ireland has three transmission system operators, namely MEL, BGTL and BGÉ (UK) Ltd. The transmission companies are required under their respective conveyance licences to prepare plans for the operation, development and maintenance of the transportation system. Additionally, the transmission companies are required under their respective network codes to jointly publish a Northern Ireland Capacity/Pressure Report each Gas Year. The publication of the JGCS meets these requirements.

2.6 Planned Network Components

2.6.1 Supply Sources

There are a number of prospective projects still at development stage, which may have an impact on the system. These include the potential construction of gas storage in salt cavity layers at Larne, the planned Liquefied Natural Gas (LNG) import terminal on the Shannon Estuary, and the proposed expansion of storage by PSE Kinsale Ltd. These are discussed further below.

Islandmagee Storage Limited, a consortium of Infrastrata plc, Moyle Energy Investments Ltd and BP Gas Marketing Ltd, propose to develop a 500 mscm salt cavity storage facility under Lough Larne. Islandmagee Storage Limited has completed seismic testing and recently received planning permission for the storage facility and grant of a licence to store gas in October 2012. The consortium is continuing to progress the project including plans for the drilling of a test borehole. The Islandmagee storage developers have indicated 2017/18 as a possible start date for commercial operation.

The gas storage facility will be located adjacent to the SNIP and it is expected that no extensive pipeline development will be required to facilitate connection.

The proposed LNG terminal at Ballylongford will be connected to the existing transmission system by c. 26km of pipeline. The construction of the terminal has received planning permission (subject to certain conditions), and the necessary consent for the pipeline to the transmission system was granted by the CER in December 2009.[8]

PSE Kinsale Energy has identified two possible future operational scenarios. Kinsale Energy has indicated, as Celtic Sea gas production is gradually declining, the existing storage operations will not be economic on a standalone basis and the lifetime of the facility is dependent on gas markets. The first scenario, taken to be the base case scenario, in which the cessation of storage operations and blow-down of the cushion gas from the South

West Kinsale facility commences in April 2014, with total cessation around 2017. A second supply scenario sees the existing storage operations continuing up to the gas year 2020/21.

Eirgas Ltd, a subsidiary of Providence Resources, are currently examining the feasibility of gas storage in the Irish Sea as part of the Ulysses Project. The Ulysses Project, which commenced in 2008, is focused on potential gas storage and carbon sequestration in the Kish Bank Basin, offshore Dublin.

Recently Providence Resources commenced flow testing on the Barryroe prospect, the results of which are expected shortly. San Leon Energy continues exploration operations off the West coast of Ireland located in the Porcupine, Rockall, and Slyne basins on the Atlantic margin.

2.6.2 Gas Flows

Currently gas flows primarily from the East Coast in Ireland where the interconnectors reach Ireland and from the South coast through the Inch Entry Point to the main centres of demand in Dublin and Cork, and also to new towns along the Pipeline to the West. Gas flows from Corrib, as well as other proposed projects are expected to displace gas coming through the Interconnectors. In this event, gas may flow from the West of Ireland to centres of demand in the East and the South. Gas may also increasingly flow from Northern Ireland depending on the timing of the Islandmagee storage project. In NI all demands are currently supplied from Moffat via the SNIP.

Depending on the timing of the various supply projects, there is also the potential for gas demand on the island to be increasingly or wholly dependent on supplies from Moffat. The network modelling undertaken by BGN has therefore tested the implications of these potential major changes in the operation of the network and examined the potential for increased flows through the Moffat Entry point to Northern Ireland and Ireland. Therefore, the supply and demand scenarios in the JGCS serve to indicate whether or not reinforcements or other mitigation measures will be needed to accommodate these projected flows. The supply and demand cases and the scenarios also identify whether supplies from the major supply projects in Ireland and Northern Ireland would physically flow to the other jurisdiction.

2.6.3 Network Development

Macroom in Co. Cork was approved under the gas connection policy and began to receive gas in 2012. Coothill, Co. Cavan was also approved for gas connection during the past year.

The CER's approval of the connection of new towns to the network is based upon economic analysis developed by BGN in light of the criteria outlined in the Gaslink Connection Policy. The Connection Policy is designed to encourage new customer uptake to the gas network in a manner which would be economic, efficient and transparent, while at the same time minimising adverse impacts on gas network charges.

Regarding network development in Northern Ireland, the Department of Enterprise, Trade and Investment (DETI) has developed an outline business case seeking government funding to extend the gas network to the west of Northern Ireland. Consideration of the business case is ongoing.

2.6.4 Network Reinforcement/Refurbishment

Subject to regulatory review and approval in the relevant jurisdictions, the TSOs carry out reinforcement of the existing gas transmission network to ensure system demand is met, to facilitate local development and to upgrade old pipelines etc. Reinforcement projects that were completed by Gaslink/BGN during gas year 2010/2011 include:

- Waterford Reinforcement work was completed in 2 phases. The first was completed in June 2010 and the other completed in September 2010.

There is a continuous programme in both jurisdictions to review and refurbish the gas transmission system, to ensure that it continues to comply with all of the relevant legislation, technical standards and Codes of Practice. This refurbishment work is coordinated with reinforcement work (where possible), to minimise overall costs and to limit disturbance to local communities.

The following refurbishment and diversion projects were undertaken by Gaslink/BGN during gas year 2009/10:

- The Dublin 4 lightwall refurbishment project was completed between Irishtown and Belfield, The project started in June 2010 and was completed in September 2011.
- A remotely actuated emergency bypass was installed around Middleton Compressor Station for the purposes of supplying the 30 Bar Cork network in the event of a failure of the MCS Pressure Reduction System;
- Completion of Kilshane Block Valve refurbishment.

The following transmission system refurbishment and diversion projects are planned.

- Detailed integrity assessments have been carried out on the Limerick 19 barg network and it has been identified that it is necessary to eliminate the risk posed by light-wall pipe in Limerick City. In conjunction with the integrity analysis, it has been determined that there is a need to reinforce the 19 barg network in Limerick due to capacity limitations. Following approval by the CER, preliminary engineering is progressing with a view to construction commencing next year. It should be noted that the proposed solution for Limerick pushes out the need to reinforce the Limerick 70 barg network.
- Santry – Eastwall pipeline lightwall refurbishment project in Dublin City; Optimal solution for the refurbishment of the 6.5kms Santry – Eastwall pipeline is being progressed;
- Waterford Pipeline replacement project; Optimal solution for the refurbishment of 2.6kms of the Waterford City pipeline is being progressed;
- Four diversions are required to facilitate the M20 Cork to Limerick motorway. The 1st of these diversions, on the 6” pipeline near Mallow Hospital is due to be carried out this year with the remaining 3 diversions to follow
- Following the redevelopment of Great Island to a 459MW CCGT a 45km pipeline from Baunlusk co. Kilkenny to Great Island. Co. Waterford will be required. The project commenced in September 2012 and is expected to be completed in autumn 2013. The project will require 3 AGIs.

2.6.5 Compressed Natural Gas

BGN is currently investigating the development of an Irish market for the use of natural gas as a fuel in transport. Natural Gas as a transport fuel - known as Compressed Natural Gas (CNG) – is used across the world within Natural Gas Vehicles (NGV). Since 2000, there has been substantial growth of NGVs worldwide, with approximately 30% annual growth mainly on account of the economic and environmental benefits associated with CNG. BGN has introduced a fleet of CNG and is actively engaging with interested parties to commercially use CNG within captive fleets. In collaboration with NSAI a standard for CNG refuelling station has been developed by the working group on natural gas standards.

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2.7 Overview of the gas distribution systems in Ireland and Northern Ireland

Gas is delivered by the high pressure transmission network to Above Ground Installations (AGIs) designed to reduce the pressure to a suitable level for delivery to the BGÉ distribution system. The entire distribution system comprises PE (polyethylene) pipe operating in two nominal pressure tiers of 4 bar and 75 mbar delivering gas to more than 600,000 customers’ premises in towns and cities. Planning and development of the distribution system incorporates demand forecasts based on customer information and connection requests for individual residences and new housing schemes in addition to industrial and commercial (I&C) loads.

The distribution system design in Ireland is based on 1-in-50 winter criteria applied to a standard annual load by classification of domestic residence or to customer specific information for industrial and commercial loads.

The NI distribution system is comprised of two networks – the Phoenix Natural Gas network in the Greater Belfast and Larne area which has over 150,000 customers and the Firmus energy network in the ten towns along the SNP and NWP which have around 15,000 customers. Both of the networks are entirely constructed using PE (polyethylene) pipe. The Phoenix distribution network operates in three nominal pressure tiers of 7bar, 4bar and 75mbar. The Firmus distribution network operates in two nominal pressure tiers of 4bar and 75mbar. Planning and development of the distribution network is the responsibility of the respective Distribution System Operators with development and capacity obligations set out in the respective licences.

The NI distribution system design is based on 1-in-20 winter criteria applied to a standard annual load by classification of domestic residence or to customer specific information for industrial and commercial loads.

3 Gas Demand

3.1 Introduction

This chapter provides a review of both the historical and forecast annual and peak gas demands for the Republic of Ireland and Northern Ireland. A breakdown of the overall demand by sector is presented along with a review of the peak gas demand and annual gas demands. Similarly, the forecast gas demands are broken-down by sector for both Ireland and Northern Ireland as per the 10 year period modelled in the JGCS.

3.2 Historic ROI Annual Gas Demand

3.2.1 *Overview*

ROI annual gas demand contracted by 4.6% in 2010/11 compared to 2009/10 and peak day gas demand fell by 14.1% in 2011/12 compared to the peak of 2010/11.

The reduction in annual gas demand can largely be attributed to a fall in power sector gas demand as a consequence of higher wind powered generation and reduced electricity demands. I/C gas demand grew by 13.9% in 2010/11. The increase in I/C demand was driven by the daily metered I/C customers which may be a reflection of the performance of export lead industries as well as a reclassification of the I/C sector to include CHP.

Table 3.1 summarises ROI annual gas demand for the period 2004/05 to 2010/11. Due to demand contraction in 2010/11, demands are equivalent to 2007/08 levels. ROI annual gas demand has grown by 2.3% p.a. over the last seven years. Contraction in recent years was primarily due to a reduction in the power sector gas demand and to a lesser extent by a decrease in the residential gas demand. The I/C sector showed rapid growth in 2010/11. The demand trend is summarised as follows:

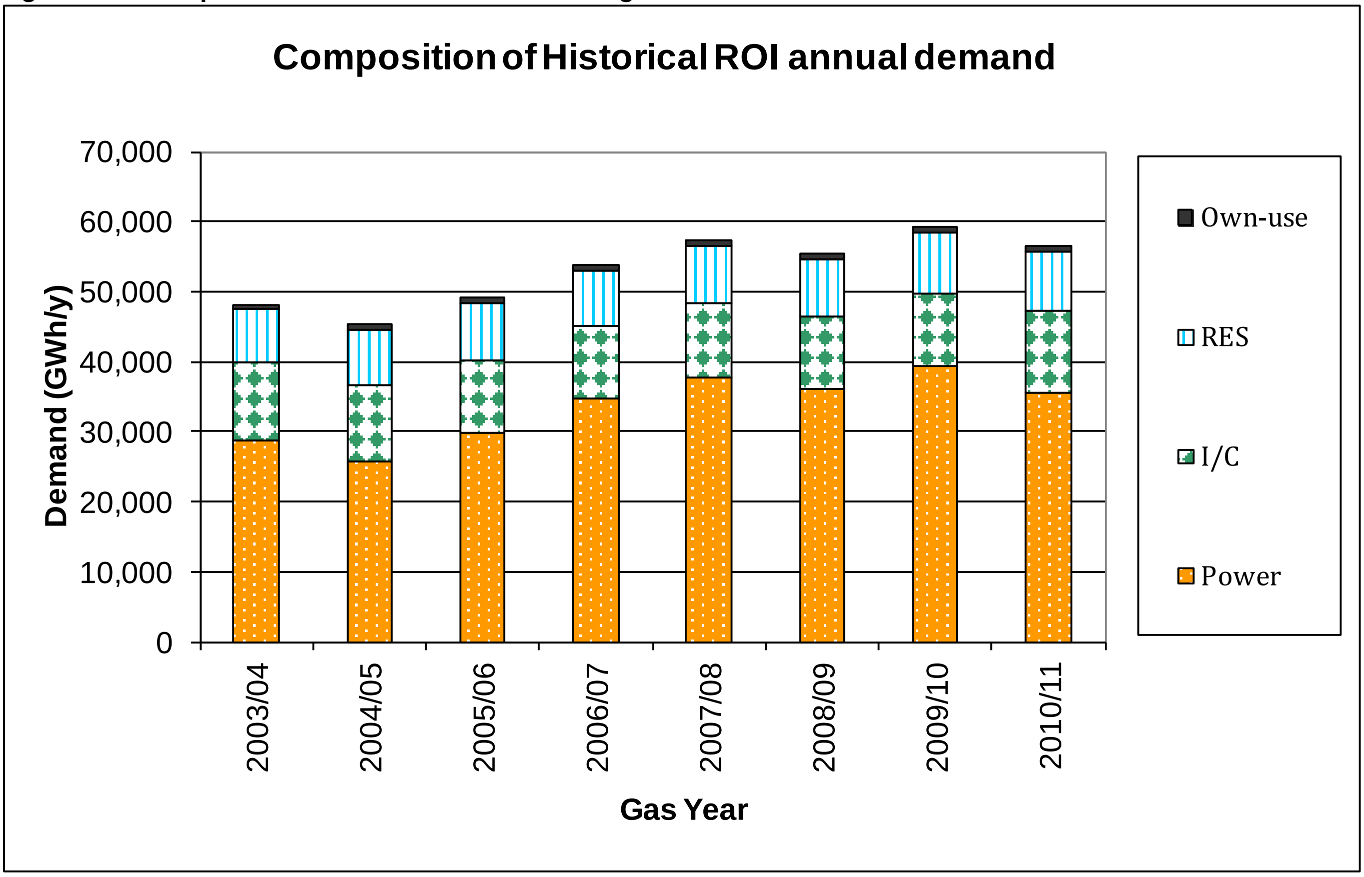
- Power sector gas demand grew by 3.0% p.a. due to the growth in overall electricity demand and the construction of new gas-fired stations, e.g. Aughinish Combined Heat & Power (CHP), the Tynagh and Huntstown II Combined Cycle Gas Turbine (CCGT) stations and the opening of the Aghada CCGT and Whitegate CCGT in April and August 2010 respectively;
- Residential gas demand grew by 1.7% p.a. since 2003/04, however, this was less than the corresponding growth in customer numbers, due to a combination of increased energy efficiency, higher gas prices, smaller dwelling sizes and greater vacancy rates; *and*
- The I/C gas demand has continued to grow in 2010/11 with the annual trend since 2003/04 showing a 1% growth per annum.

Table 3-1: Historic ROI annual gas demand[1] expressed in volume (mscm/y) and energy (GWh/y)

	Unit	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11
ENERGY								
Power[2]	GWh/y	25,630	29,775	34,688	37,758	36,007	39,338	35,432
I/C	GWh/y	11,127	10,352	10,486	10,507	10,415	10,499	11,954
RES	GWh/y	7,757	8,149	7,716	8,239	8,312	8,590	8,340
Own-use[3]	GWh/y	878	815	779	814	823	900	889
Total ROI	GWh/y	45,392	49,091	53,669	57,318	55,557	59,327	56,615
VOLUME								
Power	mscm/y	2,327	2,698	3,140	3,442	3,265	3,568	3,219
I/C	mscm/y	1,010	938	949	958	945	952	1,086
RES	mscm/y	704	738	699	751	754	779	758
Own-use	mscm/y	80	74	71	74	75	82	81
Total ROI	mscm/y	4,122	4,448	4,858	5,225	5,038	5,381	5,143
GCV								
Moffat	GJ/m^3	40.00	40.00	40.00	39.69	39.84	39.82	39.75
Inch	GJ/m^3	37.50	37.50	37.50	37.79	37.92	37.94	38.11

[1] Gas demand is summarised by "Gas Year", i.e. the period from 1st October to the following 30th September
[2] Power demand includes Aughinish CHP gas demand
[3] Own-use includes the gas consumed by the system, including fuel-gas for compressor stations & heaters

Figure 3-1: Composition of historical ROI annual gas demand



Natural gas continues to occupy a dominant position within the power generation fuel mix. The power sector share of total gas demand has grown from 56.6% in 2004/05 to a peak of 66.3% in 2009/10 and accounted for 62.6% in 2010/11 (see Figure 3-1).

The power sector's increasing share of total gas demand has resulted in a reduction in the proportion occupied by the I/C sector, whose share reduced from 23.2% in 2003/04 to a 21.1% in 2010/11 (see Figure 3-1).

The residential sector's share of total gas demand has remained at approximately 15% but this proportion is showing signs of gradual decline.

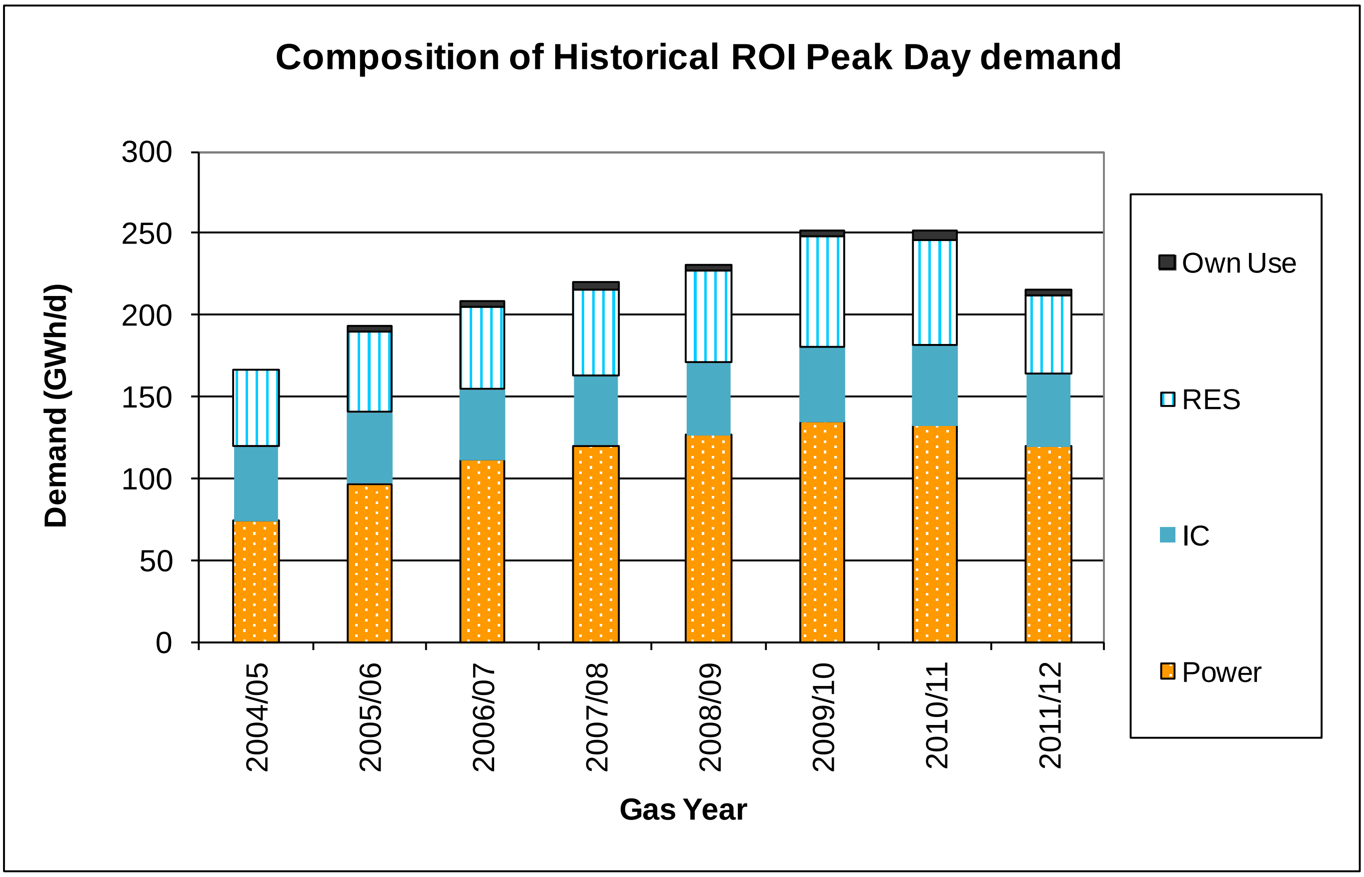
Table 3-2 presents the annual peak daily gas demand. The 2011/12 peak day analysis has been included as the 2011/12 winter period has already occurred. The peak daily demand fell by 14.1% on 2010/11 figures but has increased by 3.8% per annum since 2004/05. The growth in peak demand is largely due to an increase in the peak power gas demand which has increased by 7.2% per annum. The peak non power sector had also seen an annual increase up to 2011/12 but this has contracted in 2011/12. The reduction in non-power peak demands in 2011/12 was largely due to the 2011/12 winter period being milder than the previous 2 years.

Since 2004/05 the power sector has continuously accounted for a greater portion of the peak day gas demand. Power accounted for 44.3% of peak day demand in 2004/05 and in 2011/12 this grew to 55.4%. The non power sector portion of peak day demand has contracted accordingly, with the ratio of IC to residential remaining relatively constant. The two extreme cold weather spells experienced in 2009/10 and 2010/11 showed an increase in the weather sensitive residential sector and smaller I/C customer's gas demand in response to the extreme low temperatures. This variation in peak day demand is presented in Figure 3-2.

Table 3-2: Breakdown of the Historical ROI Peak Day Gas Demand

	Unit	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
ENERGY									
Power[2]	GWh/d	73.6	96.8	111.2	119.7	126.4	134.3	132.2	119.5
I/C	GWh/d	45.5	43.4	43.1	43.4	44.4	46.3	49.6	44.4
RES	GWh/d	47.0	49.4	50.4	52.5	56.7	67.0	64.2	47.7
Own-use	GWh/d		3.9	3.2	4.0	3.6	4.5	5.2	4.0
Total ROI	GWh/d	166.1	193.4	208.0	219.7	231.1	252.0	251.1	215.6
VOLUME									
Power	mscm/d	6.7	8.8	10.1	10.9	11.5	12.2	12.0	10.8
I/C	mscm/d	4.1	3.9	3.9	3.9	4.0	4.2	4.5	4.0
RES	mscm/d	4.3	4.5	4.6	4.8	5.1	6.1	5.8	4.3
Own-use	mscm/d	0.0	0.4	0.3	0.4	0.3	0.4	0.5	0.4
Total ROI	mscm/d	15.1	17.6	18.9	20.0	20.9	22.9	22.8	19.5
GCV									
Average	GJ/m^3	39.5	39.6	39.7	39.8	39.5	39.7	39.7	40.0

Figure 3-2 Breakdown of Historical ROI Peak Day Gas Demand



3.2.2 *Power Generation Gas Demand*

Power generation gas demand contracted by 9.9% in 2010/11. This decline has brought power sector gas demand levels closer to 2006/07 levels.

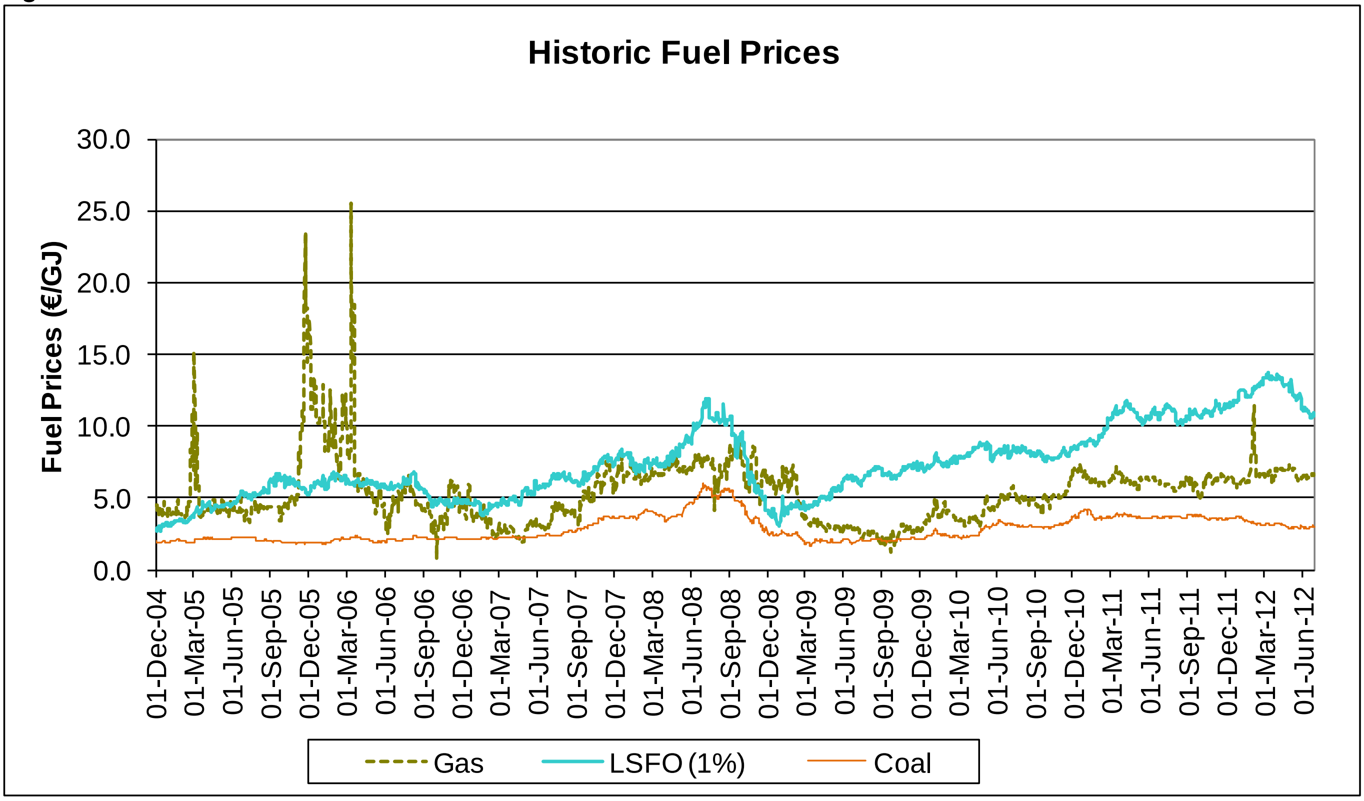
The power sector gas demand had been driven primarily by growth in the ROI demand for electricity (the Total Electricity Requirement has grown by 7.8% since 2003[9]) and the construction of new gas-fired stations. Gas-fired generation accounted for 48.2% of electricity production in 2003, increasing to 60.8% in 2011. Historic fuel prices are referenced in Figure 3.3.

A combination of lower gas prices and electricity demand growth resulted in power sector gas demand growth for subsequent years until 2008/09, when gas demand contracted due to the fall-off in electricity demand by c.-4.0% (based on EirGrid's 2008/09 Total System Demand). Following an increase in gas demand in 2009/10, due to low gas prices and cold weather events, the power sector gas demand has continued to fall in 2010/11.

The power sector gas demand recorded for the 2011/12 peak day was down significantly on previous years due to milder weather conditions and higher levels of wind powered generation.

[9] Peak day demand is determined by the Total ROI figure.

Figure 3-3: Historic Fuel Prices



3.2.3 *I/C Gas Demand*

There were 23,710 I/C customers connected to the ROI gas transmission and distribution systems at the end of the 2010/11 gas year. A breakdown of the total annual I/C gas demand by category is given in Table 3-3, in both energy and volume terms:

- TX DM I/C: 44 connections. The larger transmission connected Daily Metered (DM) I/C sites accounted for 41.1% of total I/C demand in 2010/11 which includes the larger factories and co-ops etc., who generally consume gas for use in their manufacturing/production processes;
- DX DM I/C: 239 connections. The larger distribution connected DM I/C sites accounted for 25.3% of total I/C demand in 2010/11, and includes the smaller factories, hospitals, universities, prisons etc; *and*
- DX NDM I/C: 23,427 connections. The smaller distribution connected Non-Daily Metered (NDM) I/C sites accounted for 33.7% of total I/C demand in 2010/11 and includes shops, offices, schools and restaurants etc., who generally consume gas for space heating and are therefore more weather sensitive.

Table 3-3: Breakdown of the Historical ROI Annual I/C Gas Demand[1]

	Unit	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11
ENERGY								
TX DM I/C	GWh/y	4,953	4,004	4,029	3,792	3,518	3,701	4,911
DX DM I/C	GWh/y	2,468	2,597	2,827	2,830	2,835	2,858	3,020
DXNDM I/C	GWh/y	3,706	3,752	3,629	3,886	4,063	3,940	4,023
Total I/C	GWh/y	11,127	10,352	10,486	10,507	10,415	10,499	11,954
VOLUME[2]								
TX DM I/C	mscm/y	449.8	362.8	364.7	345.6	319.0	335.7	446.1
DX DM I/C	mscm/y	224.1	235.3	255.9	257.9	257.1	259.2	274.3
DX NDM I/C	mscm/y	336.5	340.0	328.5	354.3	368.4	357.4	365.4
Total I/C	mscm/y	1,010.4	938.1	949.1	957.8	944.5	952.3	1,085.9

[1]Actual annual gas demand, no weather correction applied

[2]Volumes have been derived from the energy values by assuming a weighted GCV. Details of the Inch and Moffat GCVs are detailed in table 3.1 for each of the respective years.

It can be seen that the overall I/C demand continued to grow over the period, with a very strong growth seen in the transmission connected I/C demand. The distribution connected I/C demand also grew slightly. The growth in the transmission connected demand during the period is attributed to the strong performance of the export lead sectors of industry including dairy and food produce.

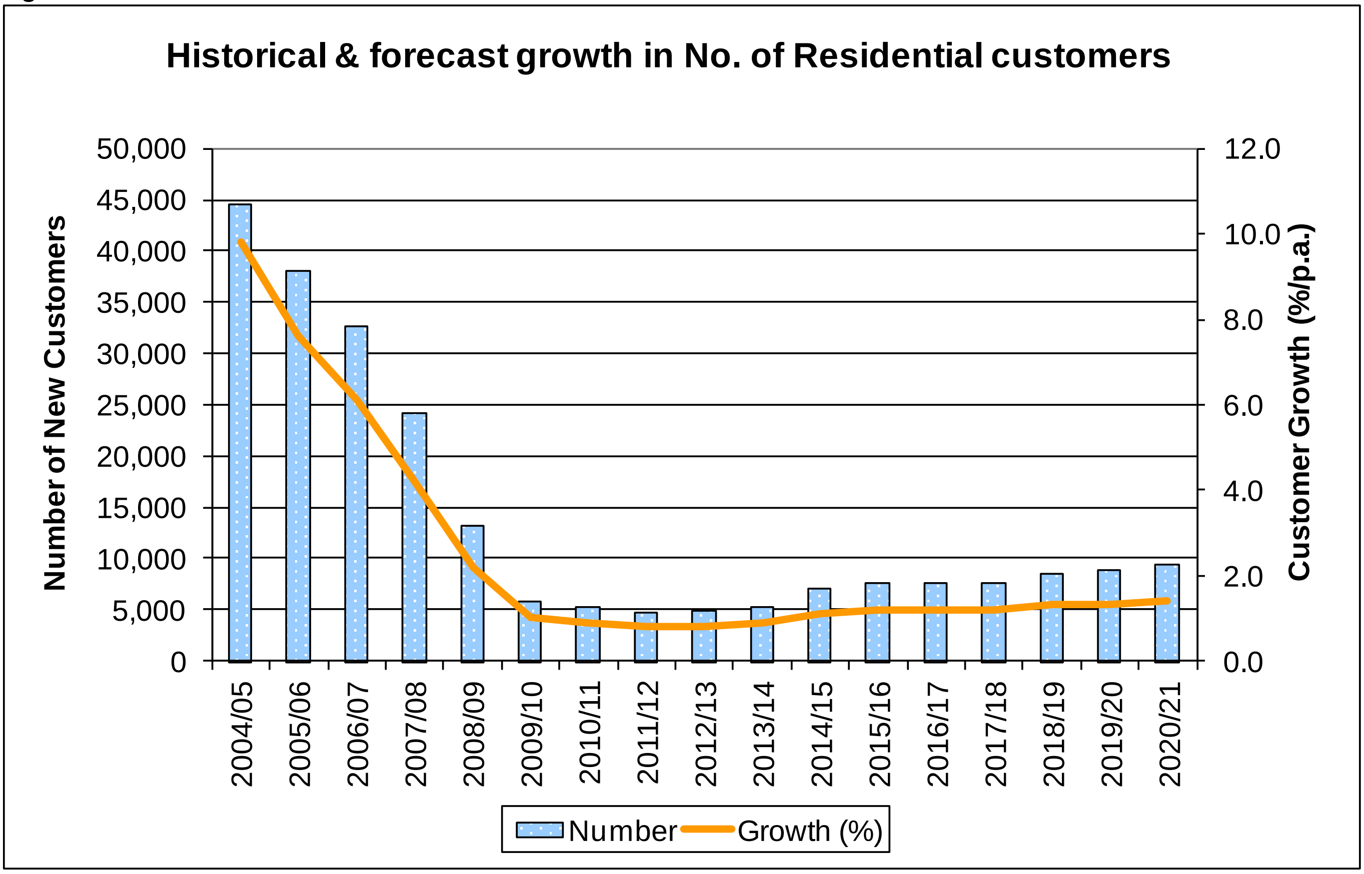
3.2.4 *Residential Gas Demand*

There were 620,292 residential customers connected to the ROI distribution system at the end of the 2010/11 Gas Year. The total number of residential gas customers has increased substantially by 23.9% since 2004/05 (see Fig. 3.4), growing from 500,837. The growth rate in customer numbers has slowed in recent years falling from 6.1% per annum in 2006/07 to 0.9% in 2010/11.

The annual residential gas demand increased by 7.5% over the same period, growing from 7,757 GWh/y in 2004/05 to 8,340 GWh/y in 2010/11. The discrepancy between the growth in customer numbers and residential gas demand has been attributed to a number of factors, including:

- increasing energy efficiency;
- varying weather conditions;
- construction of smaller dwellings (e.g. apartments etc);
- response to higher gas prices over the period; *and*
- reports of a substantial number of vacant residential properties.

Figure 3-4: Growth in New Residential Customer Numbers



3.3 Historic NI annual gas demand

3.3.1 *Overview*

The historic NI gas demand is summarised by sector in Table 3-4 and shown graphically in Fig. 3-5. The distribution category includes the gas demand of Phoenix Natural Gas and Firmus Energy, while the power sector includes the Ballylumford and Coolkeeragh power stations. The total NI annual demand has grown by 29.6% over the period 2002/03 – 2010/11 (or 3.3% p.a.).

However in more recent years total annual gas demand has fallen, until a slight increase in 2010/11. This overall decrease in demand from 2006/2007 until 2009/10 has occurred as a result of the economic recession, power generation dispatch moving from Northern Ireland to the Republic of Ireland and to an increase in renewable energy sources.

Comparing 2010/11 to 2009/10 annual gas demand in Northern Ireland has increased by 2.98% from 15,921 GWh/y in 2009/10 to 16,396 GWh/y in 2010/11, largely attributed to an increase in power sector demand by 1.85%. The increase in power sector demand was caused by the unavailability of the Moyle interconnector which resulted in lower imports and therefore increased use of gas fired power stations in Northern Ireland.

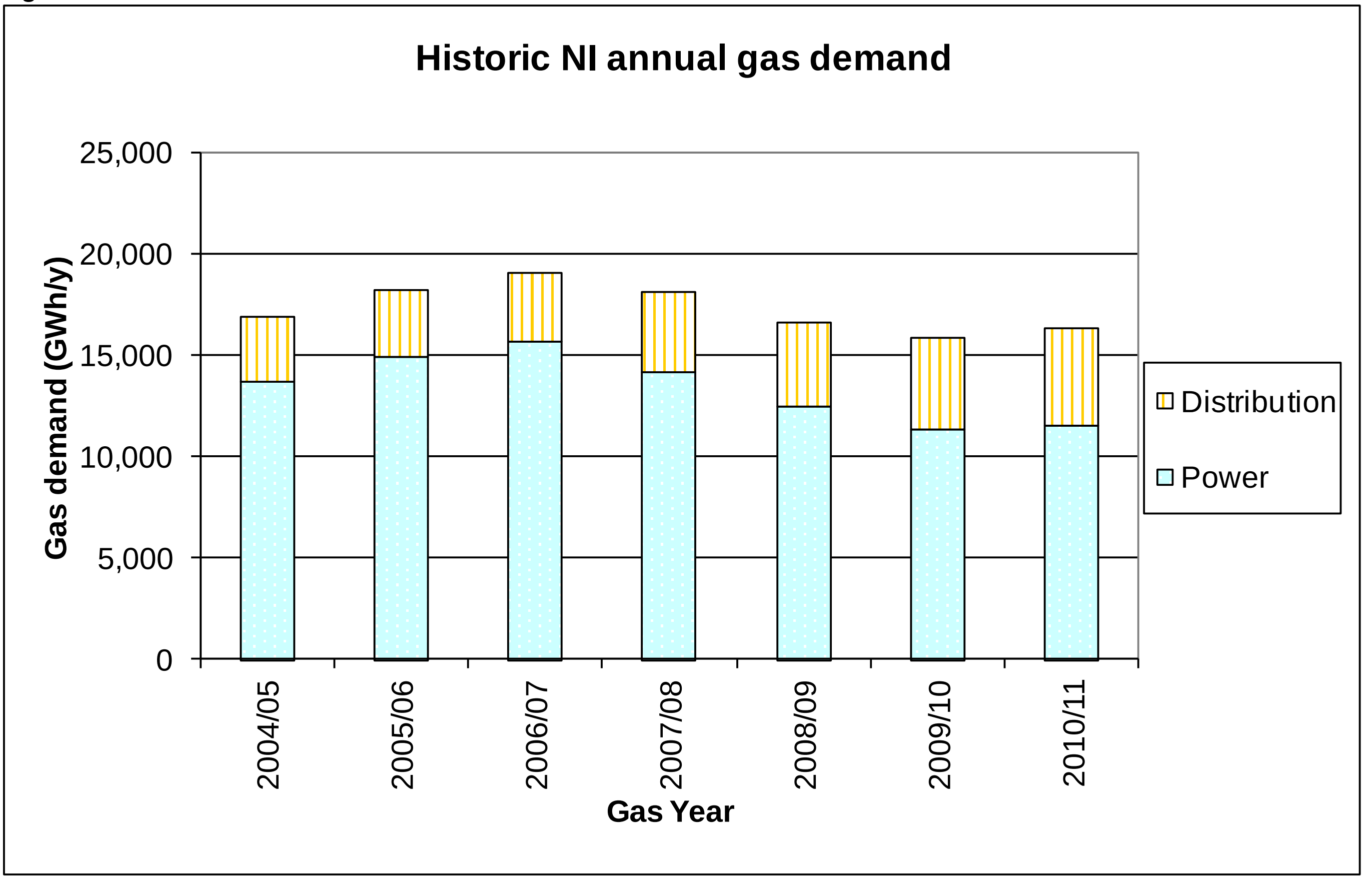
Although power sector gas demand has fallen, Table 3-4 shows a steady year-on-year increase in demand from the distribution sector reflecting the growth in domestic and industrial/commercial sectors within Northern Ireland. However since demand from the power sector accounts for a high percentage of overall total demand in Northern Ireland and due to the reduction in demand from the power sector as noted above, the total annual gas demand has decreased between 2006/2007 until 2009/10.

Table 3-4: Historic NI Annual Demand Summarised by Sector

	Unit	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11
ENERGY										
Power	GWh/y	9,881	9,903	13,770	14,922	15,696	14,249	12,489	11,352	11,562
Distribution	GWh/y	2,766	3,040	3,209	3,327	3,394	3,923	4,161	4,569	4,834
Total NI	GWh/y	12,647	12,943	16,978	18,249	19,089	18,172	16,650	15,921	16,396
VOLUME										
Power	mscm/y[1]	889	891	1,239	1,343	1,413	1,292	1,128	1,026	1,075
Distribution	mscm/y	249	274	289	299	305	356	376	413	450
Total NI	mscm/y	1,138	1,165	1,528	1,642	1,718	1,648	1,504	1,439	1,525

[1]*Volumes have been derived from the energy values by assuming a Moffat GCV of 40 MJ/m^3 for 2003/04 to 2006/07, 39.7 MJ/m^3 for 2007/08, 39.8 MJ/m^3 for 2008/09 and 2009/10, and 39.8 MJ/M^3 for 2010/11.*

Figure 3-5: Historic NI Annual Gas Demand

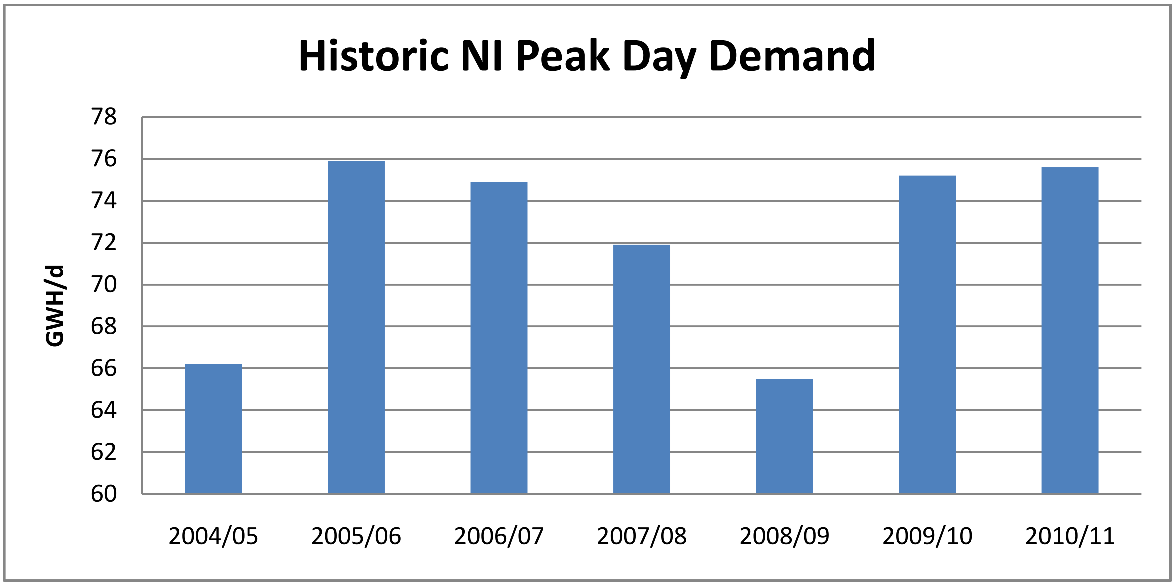


The annual peak daily demand is presented in Table 3-5 and depicted graphically in Figure 3-6. The peak daily demand fluctuates over the study years with a maximum daily demand of 75.9 GWh/d recorded in 2005/06. The recent severe winters are reflected in the peak day demands for 2009/10 and 2010/11.

Table 3-5 Annual NI Peak Daily Gas Demand

	Unit	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11
ENERGY								
Total NI	GWh/d	66.2	75.9	74.9	71.9	65.5	75.2	75.6
VOLUME								
Total NI	mscm/d	5.96	6.83	6.74	6.47	5.89	6.82	6.83

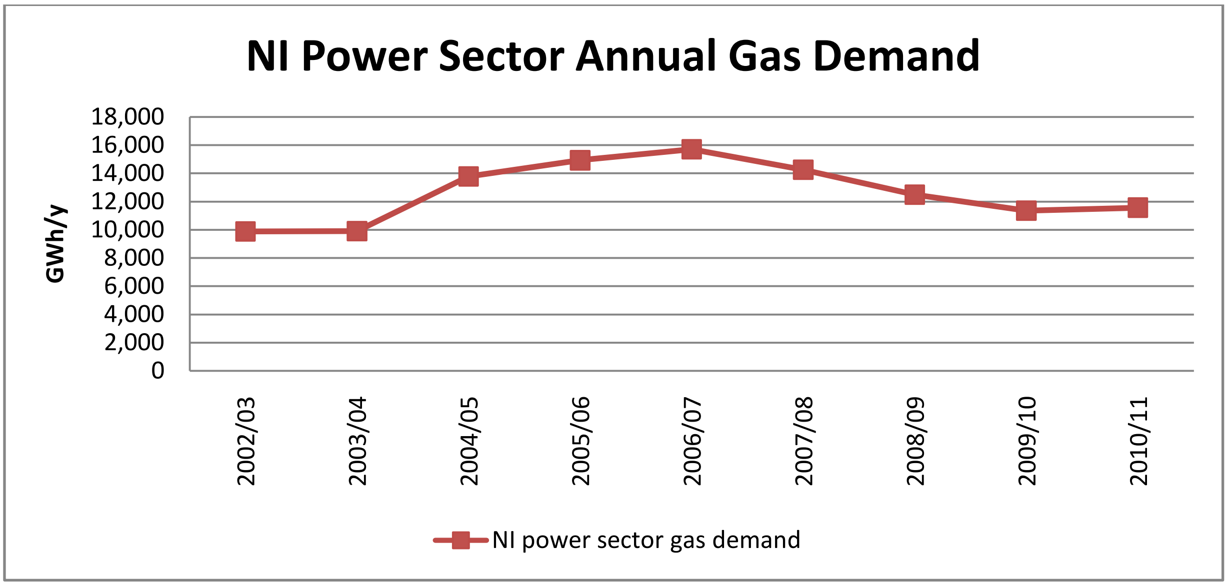
Figure 3-6 Annual NI Peak Day Gas Demand



3.3.2 *Power Generation Gas Demand*

From 2002/03 – 2010/11 the overall gas demand from the power sector in Northern Ireland grew by 1.9% p.a. However as represented in figure 3.7, the gas demand from the power sector has contracted by -26.3% (5.3%) p.a. from the peak demand recorded in 2006/07 until 2010/11. This reduction is largely due to a lower despatch order at the Ballylumford power station due to newer, more efficient generators running in the Republic of Ireland and increasing use of wind powered generation. As noted above the outage of the Moyle Interconnector caused a slight increase in the gas demand from the power sector for 2010/2011.

Figure 3.7 Northern Ireland power sector gas demand



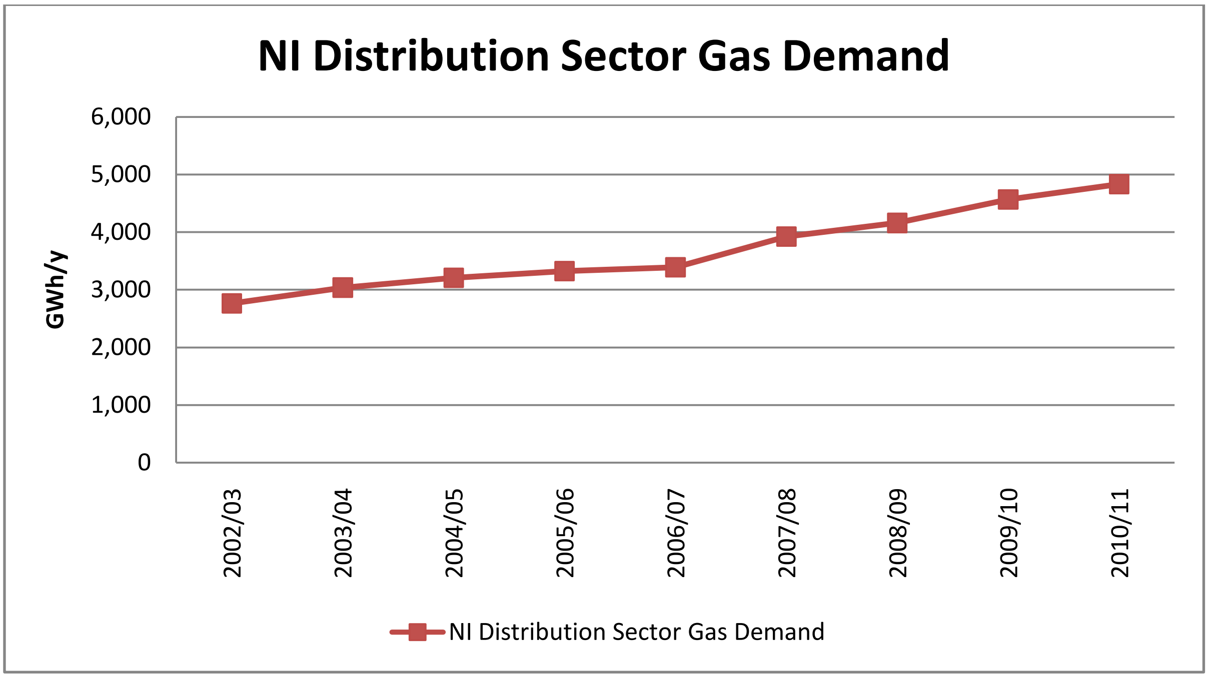
3.3.3 *Distribution Gas Demand*

The overall distribution sector has grown by 8.3% p.a. between 2002/2003 and 2010/11. This represents steady growth within the Phoenix Natural Gas distribution system in the Greater Belfast area and the Firmus distribution systems along the North West Pipeline (NWP). The historic distribution demand for the Phoenix Distribution system and Firmus distribution system is summarised below;

- Phoenix Distribution - The distributed gas volume in the Phoenix Natural Gas Ltd (PNG) licensed area of greater Belfast has grown by 25.0%, averaging 3.1% p.a. over the period 2003/04 to 2010/11. The increase has been driven by a growing customer base, the majority of whom are domestic customers.
- Firmus Distribution – Firmus Energy started to supply natural gas in the Firmus distribution Licensed Area 10, in 2005, increasing their sales significantly in the following years, mainly in the industrial and commercial (I&C) sector. In recent years focus has changed to connecting SMEs and domestic customers, although the high cost of alternative fuels in 2010/11 encouraged several I&C customers to convert in 2011. In 2009 Firmus Energy also started to supply gas in the Greater Belfast area.

The historic gas demand of the NI distribution sector for the period 2002/03 to 2010/11is presented below in Figure 3.8.

Figure 3.8: NI Distribution Sector Gas Demand



3.4 The ROI Gas Demand Forecast

3.4.1 *Introduction*

A single gas demand forecast was developed for the 2012 JGCS, which includes a combined forecast for both Ireland and Northern Ireland. The methodologies used to develop the relevant components of the demand forecast in this year's JGCS are consistent with last year's JGCS, and may be briefly summarised as follows:

[10] Antrim, Armagh, Ballymena, Ballymoney, Banbridge, Coleraine, Craigavon, L'Derry, Limavady and Newry

- The gas demands for the different sectors of the ROI economy were modelled separately using a combination of historic gas demand information, provided by shippers and other stakeholders, future expectations of economic growth, new housing construction, electricity demand and fuel-prices.
- The future gas demand for NI was derived from information primarily provided by shippers as part of the "Postalised" tariff arrangements as part of the JGCS. The postalised demand figures were reviewed and updated to reflect the distribution companies' expected connection profiles for the period modelled. Similarly demand forecasts for the power generation sector were reviewed and updated to reflect their latest modelling assumptions.

3.4.2 *ROI gas demand forecast methodology*

Separate gas demand forecasts have been prepared for the power generation, I/C and residential sectors, since each sector has quite different gas demand drivers. These individual forecasts were then aggregated to give the overall gas demand forecast for Ireland. The methodology used to generate the forecast for each sector may be briefly summarised as follows:

- The gas demand for the power sector was generated using a simple "merit-order" stack-model to determine how power stations would be dispatched to meet the forecast hourly electricity demand, and to calculate the daily gas demand of the despatched stations;
- The historic weather adjusted I/C demand is assumed to grow (or contract) at 80% of 'Real' Gross Domestic Product (GDP)[11], i.e. it is assumed to grow or contract in line with economic growth or recession, after adjustment for energy efficiency; *and*
- The historic weather adjusted residential gas demand is assumed to grow in line with increasing customer numbers, after including adjustments for energy efficiency.

The underlying assumptions for the above modelling work in terms of future electricity demand, the level of new housing construction, GDP growth and energy efficiency were agreed by the JGCS working group. Many of these inputs were sourced from external sources such as the ESRI and EirGrid.

The detailed demand modelling was then carried out by BGN using the agreed inputs. A more detailed description of both the modelling methodology for each sector, and the associated inputs are given in the following sections.

It is to be noted that volumes presented as part of the forecast annual demand data have been derived from the energy values by assuming a weighted GCV based on the Base supply scenario unless otherwise stated.

3.4.3 *ROI 1 in 50 Year Peak day gas demand forecast methodology*

The 1 in 50 year forecast examines an extreme cold weather event which has a 2% probability of occurring. While such an event has a low likelihood of occurrence in any one year. The occurrence of a 1 in 50 year event in any particular year has no impact on the probability of a similar event occurring in any subsequent years. For this reason the probability of a 1 in 50 year weather event occurring the next year, or any subsequent years, after a 1 in 50 year event has occurred remains at 2%. The Republic of Ireland system peak of 252.9 GWh/d (23.0 mscm/d) occurred on 7th January 2010 and coincided with a 20.7 Degree Day (DD) at Dublin Airport, slightly short of the then 1-in-50 DD of 21.0. The winter 2010/11 system peak of 251.2 GWh/d (22.6 mscm/d) occurred on the 20th December 2010 and coincided with a 19.9 Degree Day (DD) at Dublin Airport. These two events provide evidence of two separate extreme cold weather events, each with near 1 in 50 year properties, occurring in consecutive years.

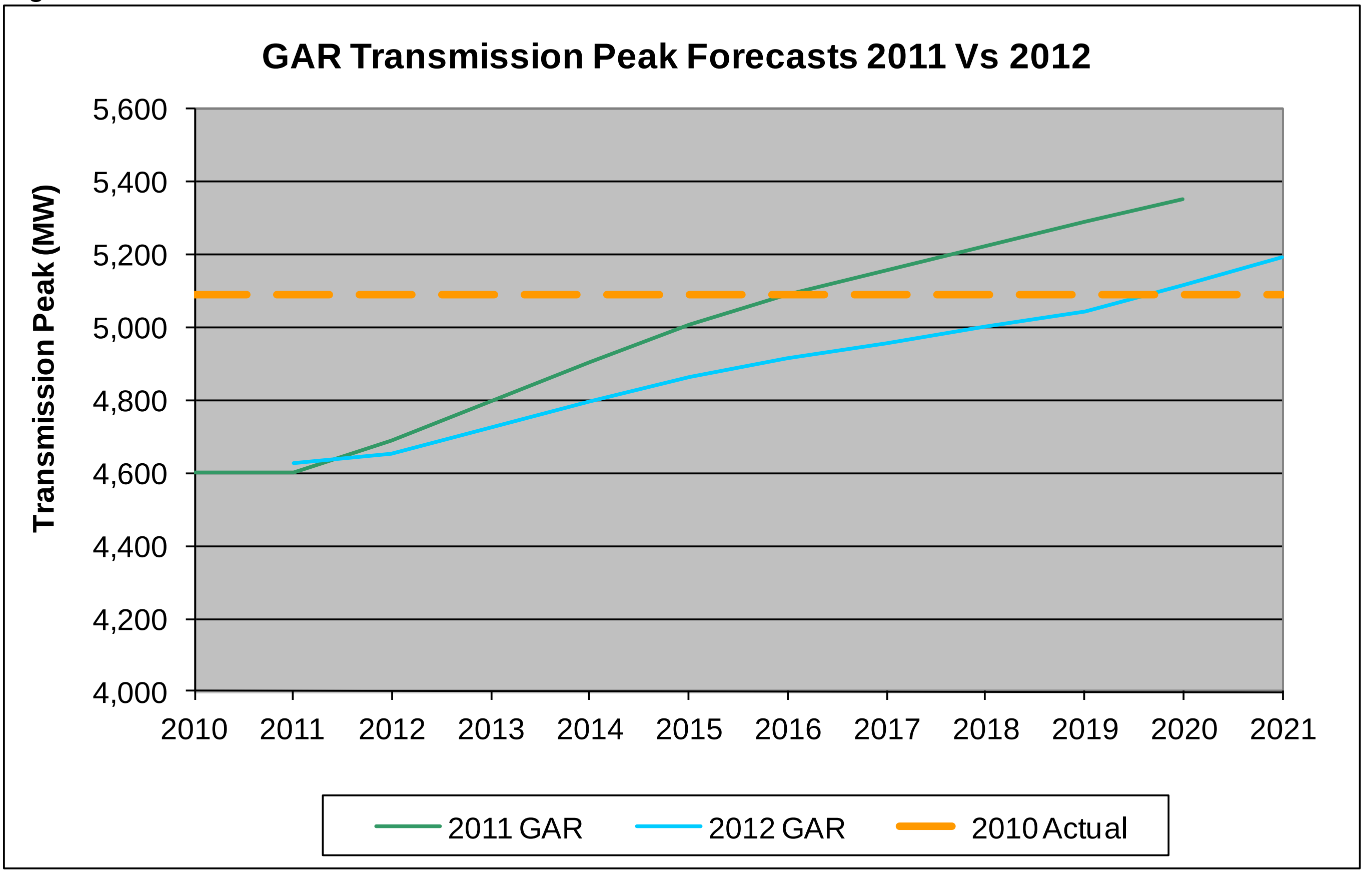
3.4.4 *Power sector demand*

The future gas demand from the power generation sector is determined by a number of factors, including the overall demand for electricity, the level and availability of renewable generation, the level of electrical interconnection with Great Britain (GB), the construction of new gas-fired power stations and the order in which power stations are despatched to meet demand (i.e. the generation merit-order).

[11] See Section 3.5.4 below.

The latest EirGrid & SONI *All-Island Generation Capacity Statement, 2012 – 2021* (AGCS) illustrates a further downward revision on the previous year's Generation Adequacy Report (GAR) forecast as a result of the continued impact of the current economic recession (see Figure 3-8)**.** EirGrid anticipate that electricity peak demand will not return to the 2010 levels until 2019. However, EirGrid forecast for average cold spells and so do not publish a forecast for severe weather conditions such as those which occurred in January and December 2010.

Figure 3-8: EirGrid GAR 2010 and 2011 Median Demand Transmission Peak Forecast



The latest EirGrid AGCS (2012 – 2021) median forecast growth rates were considered by the working group to be most appropriate for modelling purposes. Analysis was carried out using both an average and a peak electricity demand requirement. The average electrical demand is in line with the median forecast of the AGCS while the peak forecast allows for the median forecast growth rates to be applied to the actual all island 2010 peak demand figure of 6,955MW. The historic and forecast annual Total Electricity Requirement (TER) is shown in Figure 3-9 together with the corresponding growth rates.

The electricity transmission peak demand forecasts published by EirGrid & SONI in the 2012-2021 AGCS are based on a temperature standard known as Average Cold Spell (ACS), which represents an average type winter. Currently EirGrid and SONI don't publish transmission peak demand forecasts for a severe winter.

The EirGrid & SONI peak demand forecast is used for average year peak day power generation gas demand forecasts only. The actual ROI electricity transmission peak, 5,090 MW, which occurred on 21st December 2010, in conjunction with the growth rates derived from the electricity transmission peak forecasts published by EirGrid & SONI, is adopted for the 1-in-50 peak day power generation gas demand forecasts.

The AGCS Median Case scenario assumes electricity demand will grow slowly to recover to 2008 levels by 2016, with continued growth at c. 0.9% per annum post 2016. The annual ROI TER grew by 5.1% p.a. between 2004 and 2010, but has contracted sharply in 2011.

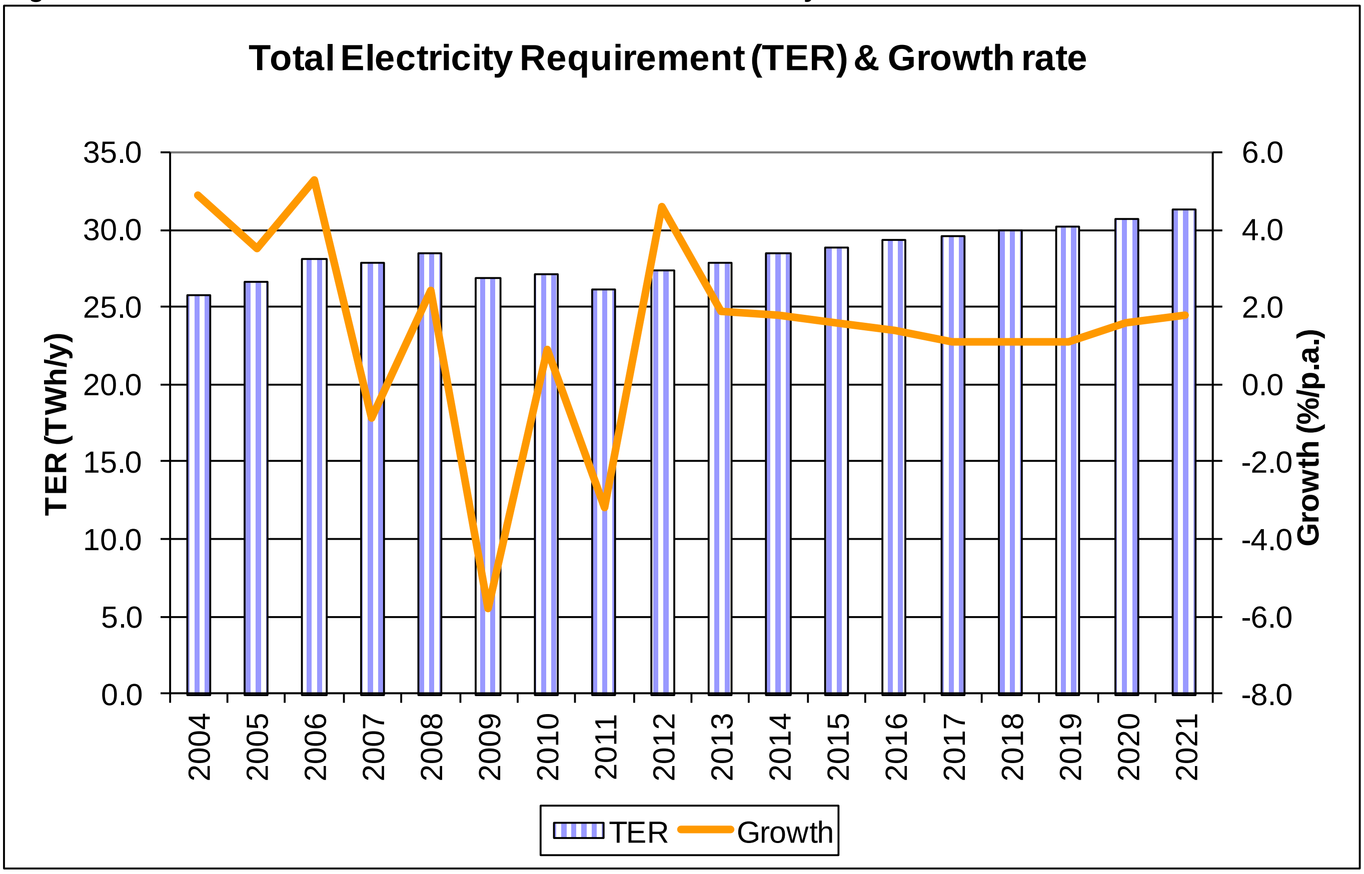
BGN's demand modelling assumes the 1-in-50 peak electrical ROI demand is to grow from 5,137 MW in 2011/12 to 5,720 MW by 2020/21. The all island demand is anticipated to increase form 7,017 MW to 7,863 MW over the same period. The growth rates applied are as per the AGCS median case scenario.

The level of future renewable generation construction has also been taken from the latest AGCS. This anticipates that the installed wind-powered generation in Ireland will increase from 1,629 MW in 2011 to c. 3,918 MW by the end of 2020.

Wind is obviously an intermittent resource, and the average annual Load Factor (LF) of wind-powered generation is c. 31.5%. This means that there will continue to be a substantial requirement for conventional thermal generation to back-up the wind generation, particularly on low wind days.

Since gas-fired CCGT and Open Cycle Gas Turbine (OCGT) generation currently appears to be the technology of choice for new power station projects, most of the new generation capacity required to back-up the wind-powered generation is likely to be gas-fired.

Figure 3-9: Historical and Forecast ROI Annual TER & Electricity Growth Rates



It is assumed that the 500 MW East-West electricity Interconnector (EWIC) connector with GB will be fully operational by 2012/13 and will operate with a 450 MW annual average capacity. The assumptions in relation to both the construction of new power stations and the retirement of existing power stations are tabulated in Table 3-6, and may be briefly summarised as follows:

- It is assumed that Scottish and Southern Energy (SSE plc.) will construct both a 459 MW CCGT at Great Island in 2013 and also retire the existing on-site oil-fired stations once the new gas-fired stations are fully commissioned;
- The forecast also includes provision for three new 100 MW OCGTs to provide the necessary flexibility to back-up the additional renewable generation which is forecast to come on line.

In aggregate the JGCS 2012 forecast assumes that 753 MW of new thermal generation capacity will be commissioned on the island over the forecast period. This additional generation will be required to meet the future growth in electricity demand, and to replace 1,395 MW of capacity which is expected to retire over the same period.

Table 3-6: Summary Assumptions for Build of New Power Stations & Retirement of Old Stations

Name	Type	Location	Export Capacity (MW)	Start/Close Date
NEW STATIONS				
Great Island	CCGT	Wexford	459	Oct - 13
Nore	OCGT	Kilkenny	98	Jan - 14
Athlone	OCGT	Westmeath	98	Jan - 15
Suir	OCGT	Tipperary	98	Jan - 16
Total			753	
RETIREMENTS				
Ballylumford (Units 4,5 & 6)	Gas	Antrim	510	Dec-15
Great Island	Oil	Wexford	216	Sep-13
Marina	Gas	Cork	85	Sep-14
Tarbert (Units 1,2 & 3)	Oil	Kerry	348	Dec-13
Tarbert (Unit 4)	Oil	Kerry	240	Dec-20
Total			1,395	

A simple merit-order stack approach was used to model the order in which power stations are likely to be despatched to meet electricity demand in Ireland. This approach assumes that power stations will be despatched in order of increasing Short Run Marginal Cost (SRMC), until the hourly electricity demand is satisfied.

The process in which power stations are stacked in order of increasing SRMC is illustrated in Figure 3-10, which shows the generation "Price/Quantity" curve, i.e. the total quantity of generation available at a given shadow price (i.e. the SRMC excluding start-up costs). The JGCS forecast assumes the following peak-day merit-order, based on the current forward fuel price curves for the winter period:

- Renewables, hydro and peat will be despatched first on a "must-run" basis;
- Followed by coal-fired generation;
- Followed by new gas-fired CCGTs;
- Followed by older gas-fired CCGTs;
- Followed by gas fired OCGTs; and
- Followed by oil-fired, i.e. Low Sulphur Fuel Oil (LSFO) power stations;

The generation merit-order is obviously very sensitive to the forward fuel-price assumptions, and on the basis of the current outlook coal fired generation occupies the base load position throughout the year with gas prices increasing slightly in winter and becoming more competitive in summer periods.

Electricity imports from GB were also included in the merit-order, using the British Electricity Trading Transmission Arrangements (BETTA) forward prices for the off-peak and peak-periods as a proxy for their SRMC cost. Again the level of future electricity imports is very sensitive to future fuel-prices.

Fig. 3-11 shows the order in which power stations are assumed to be despatched over the 24-hour period on the peak-day, summarised by fuel-type. This shows that gas demand from the power sector is already effectively "saturated", i.e. there is already more than sufficient existing peat, coal and gas-fired power stations to meet the baseload electricity demand. Peak day demand is based on actual 2010 peak demand combined with EirGrid and SONI electricity demand growth forecasts**.**

It can also be seen from Fig. 3-11, that some existing gas-fired stations are already turned-down at night due to insufficient electricity demand. The additional gas demand from new gas-fired power stations is therefore likely to be offset by reduced gas demand from the older and less efficient gas-fired stations (which will be forced further up the generation merit-order and despatched less frequently).

Figure 3-10: All Island Generation price duration curve (2011/2012)

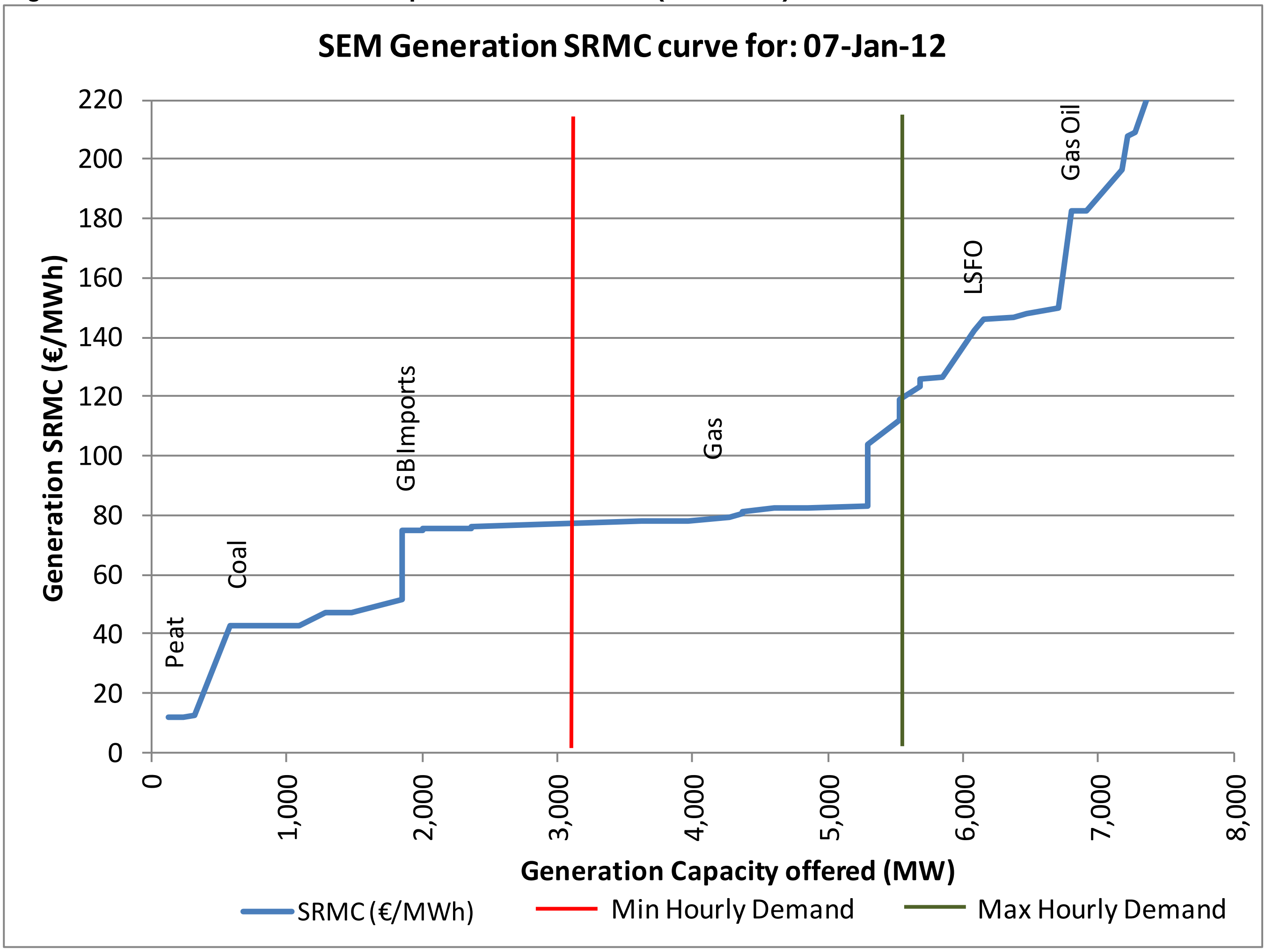
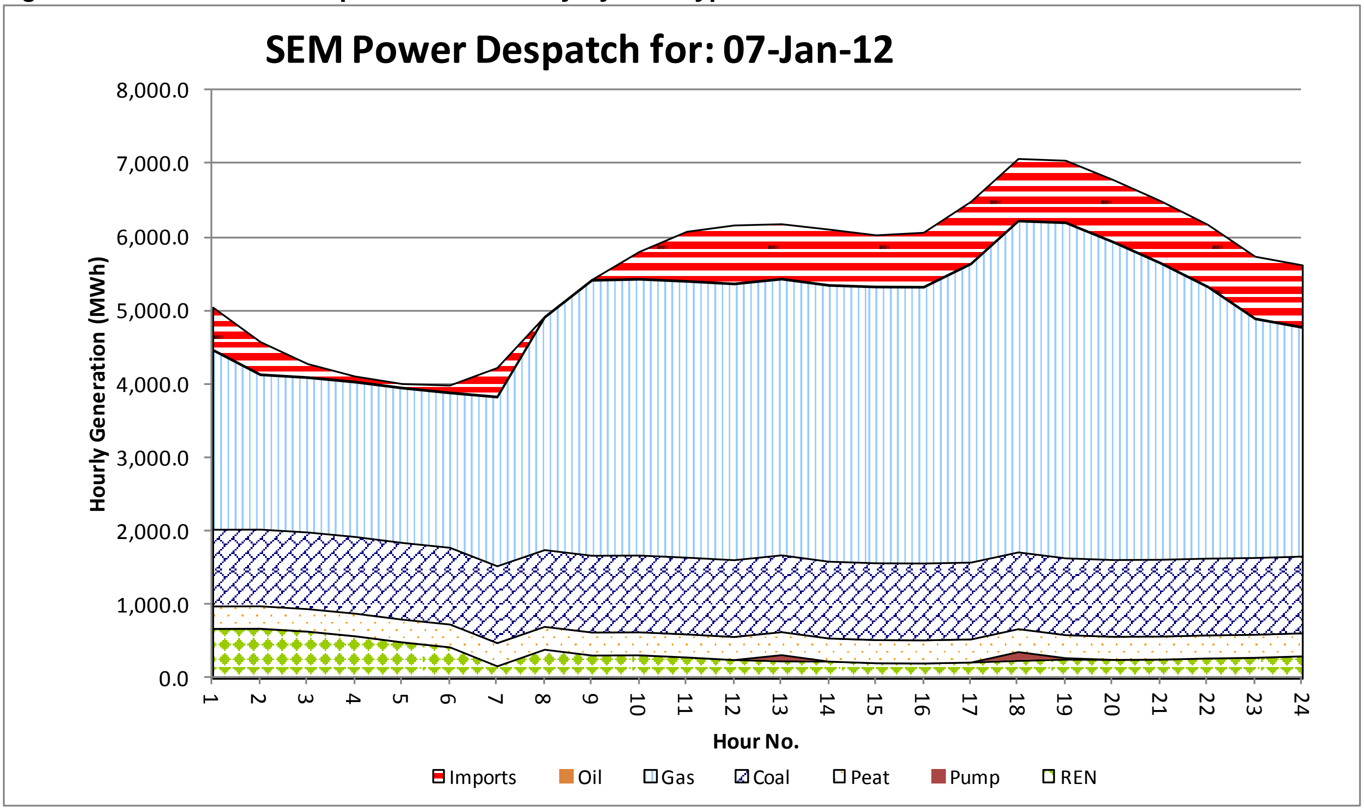


Figure 3-11: Generator Despatch on Peak-day by Fuel-type

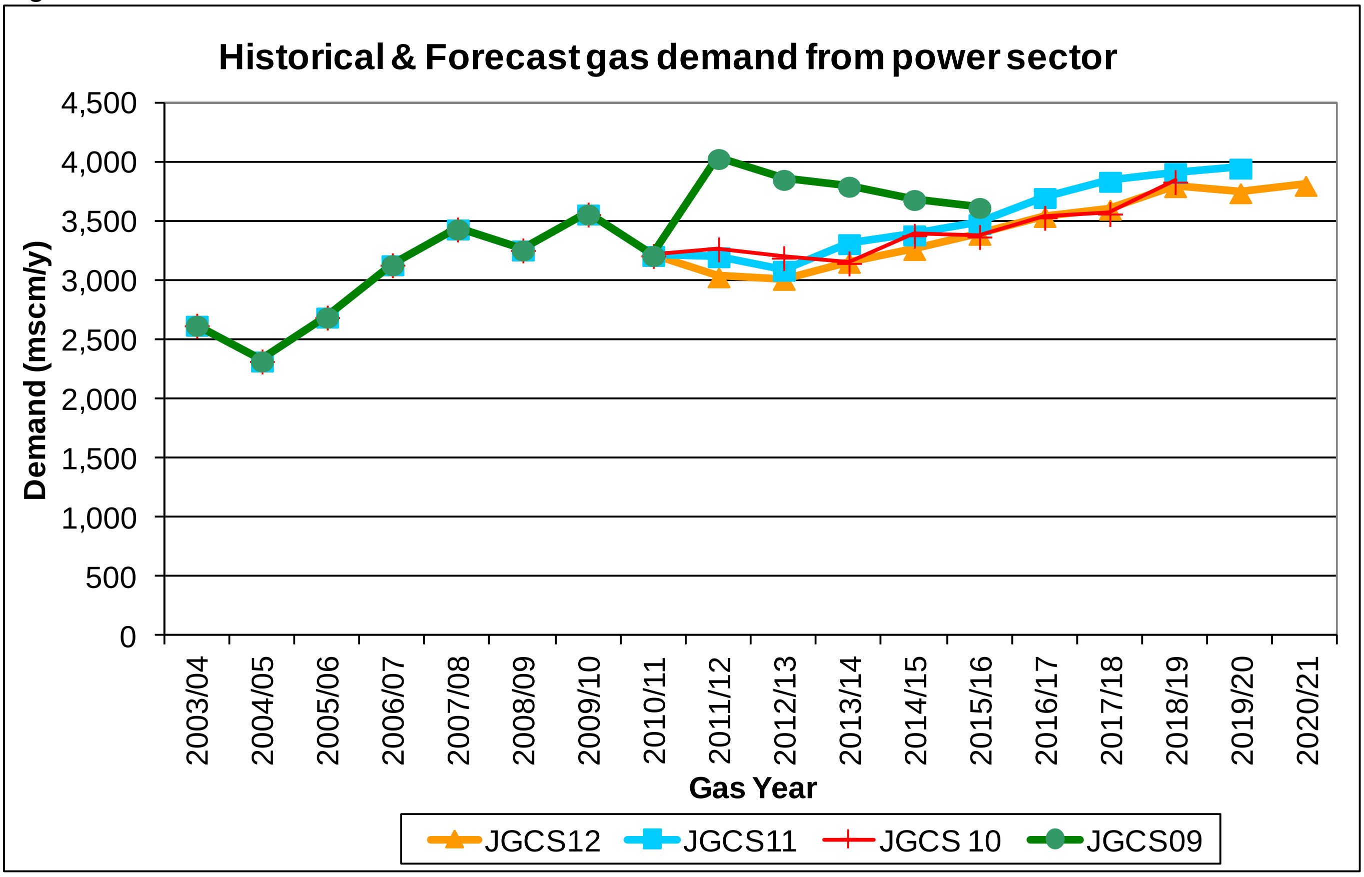


The JGCS 2012 forecast annual gas demand of the power sector is presented in Table 3-7 in both energy and volume terms, together with the corresponding forecasts from the 2011 and 2010 JGCS and the 2009 JGCS. The historical and forecast annual gas demand of the sector is shown in Fig. 3-12.

Table 3-7: Forecast Annual Gas Demand of Power Sector in Ireland

	Unit	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Energy											
JGCS 12	TWh/y	30.1	33.3	34.8	35.9	36.4	38.3	39.1	41.2	40.6	41.4
VOLUME											
JGCS 12	mscm/y	2,745	3,016	3,160	3,269	3,397	3,547	3,609	3,799	3,748	3,810
JGCS 11	mscm/y	3,208	3,093	3,318	3,392	3,487	3,708	3,845	3,918	3,956	
JGCS 10	mscm/y	3,274	3,200	3,155	3,389	3,379	3,541	3,573	3,842		
JGCS 09	mscm/y	4,037	3,861	3,803	3,691	3,624					

Figure 3-12: Annual Historical and Forecast Gas Demand for the Power Sector



As regards the overall outlook for the power sector, future gas demand is being suppressed by lower electricity demand forecasts, continued investment in renewable electricity production, increased electricity interconnection with GB and rising gas prices.

As a result of these factors the power sector gas demand has contracted between 2011/12, however recovery is expected from 2012/13 due to;

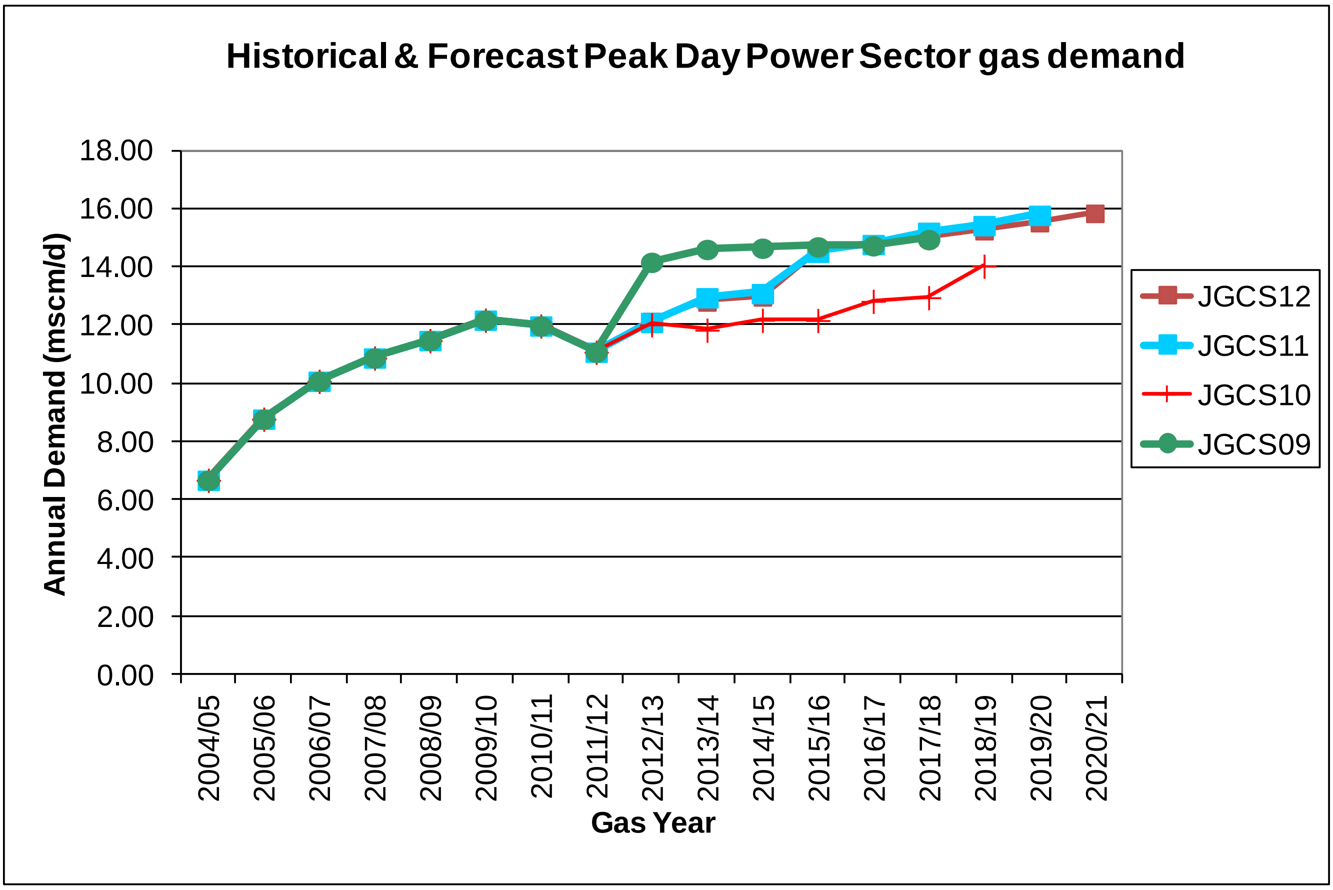
- anticipated recovery of electricity demand;
- commissioning of new more efficient gas fired generation securing a higher merit order ranking;
- increasing carbon prices results in gas fired generation becoming more competitive in the thermal generation mix;
- potential lower electricity imports as a result of reduced BETTA prices in the UK in 2015/16 due to coal plant closures following the implementation of the Large Combustion Plant Directive.

The 1 in 50 year peak day gas demand forecast for the power sector is presented in Table 3-8. The 2011/12 peak forecast was 20% higher than actual due to weather conditions which were significantly milder than the 1 in 50 peak year conditions. The peak demand is expected to continue to grow from 2013/14. This trend coincides with the JGCS 2011 predictions as presented in Figure 3-13.

Table 3-8: Forecast Peak Day Gas Demand of Power Sector in Ireland

	Unit	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Energy										
JGCS 12	TWh/y	133.8	141.3	143.2	158.0	161.3	164.4	166.9	170.0	173.7
VOLUME										
JGCS 12	mscm/y	12.2	12.8	13.0	14.5	14.8	15.1	15.3	15.6	15.9
JGCS 11	mscm/y	12.1	13.0	13.1	14.5	14.8	15.2	15.4	15.8	
JGCS 10	mscm/y	12.0	11.9	12.2	12.2	12.8	13.0	14.1		
JGCS 09	mscm/y	14.2	14.6	14.7	14.7	14.8	15.0			

Figure 3-13: Historical and Forecast Daily Peak Gas Demand for the Power Sector



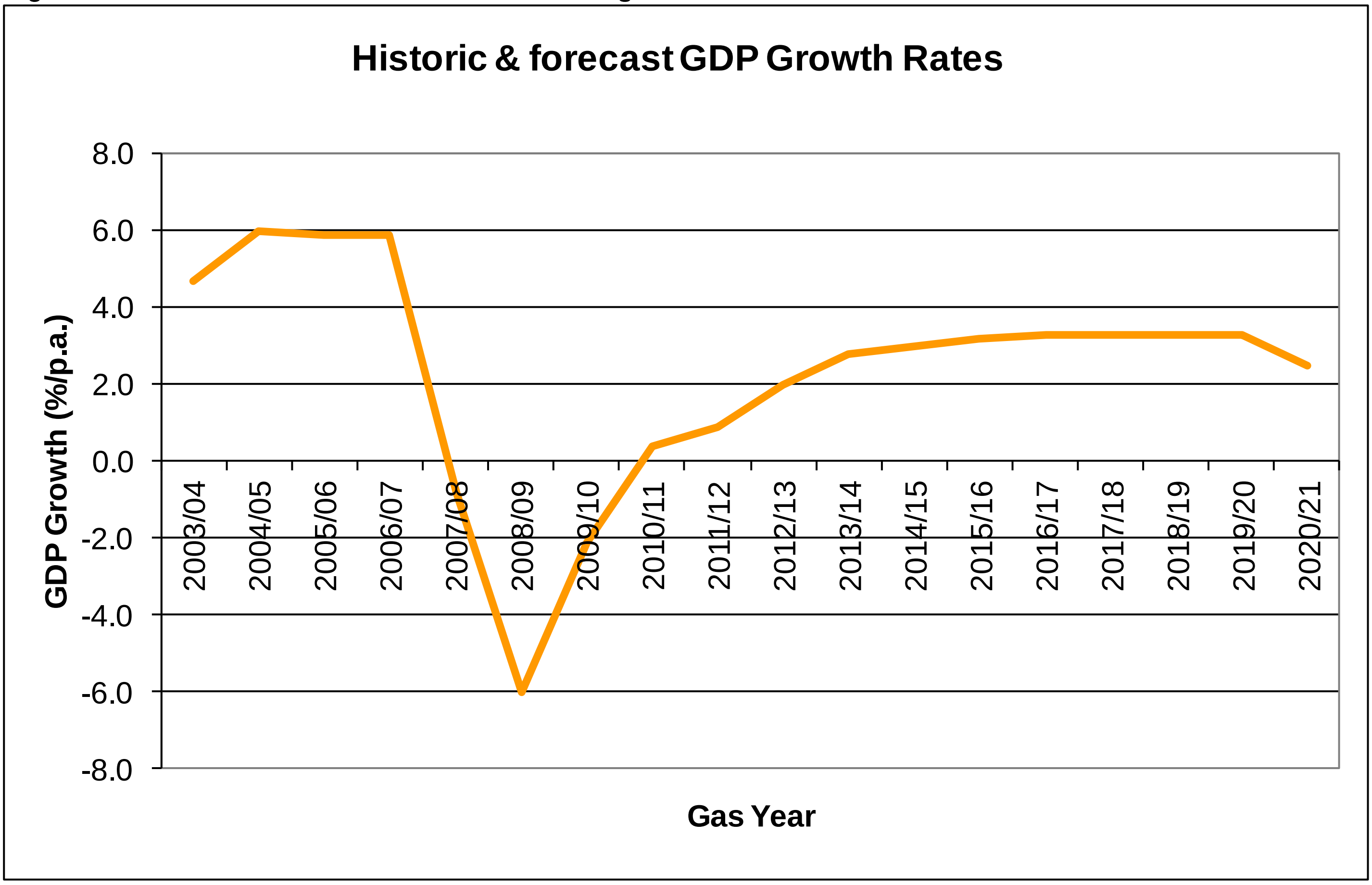
3.4.5 *ROI Industrial/Commercial (I/C) gas demand*

The drivers of I/C gas demand are complex and range from macro factors such as the overall level of economic growth to micro factors that are unique to individual industrial sectors.

It has been assumed for modelling purposes that the overall I/C annual gas demand will broadly grow/contract at 80% of the overall economic growth rate, as measured using 'Real' GDP. Real GDP is calculated using constant prices whereas nominal GDP is calculated using current prices.

The underlying GDP projections are shown in Fig. 3-14. However, some of this growth will be offset by increasing energy efficiency measures assumed for the I/C sector.

Figure 3-14: Historic and Forecast ROI 'Real' GDP growth rates



The starting point for the GDP forecast was the ESRI Quarterly Economic Commentary (QEC) for winter 2011, which assumed that the ROI GDP would grow by 0.9% in 2012 and 2.3% in 2013.

A pragmatic approach was adopted to counter the absence of any updated GDP forecast beyond 2013, following consultation with the ESRI. The forecast assumes strong economic recovery in 2013, when GDP is anticipated to increase to c. 2.3% in 2013 and maintain average growth c.3.0% each year up to 2016, and revert to its long-term growth potential of c. 3.3% p.a. from 2016. The resultant I/C demand forecasts are summarised in Table 3-9, together with the corresponding forecasts published in previous JGCS (see also Fig. 3-15).

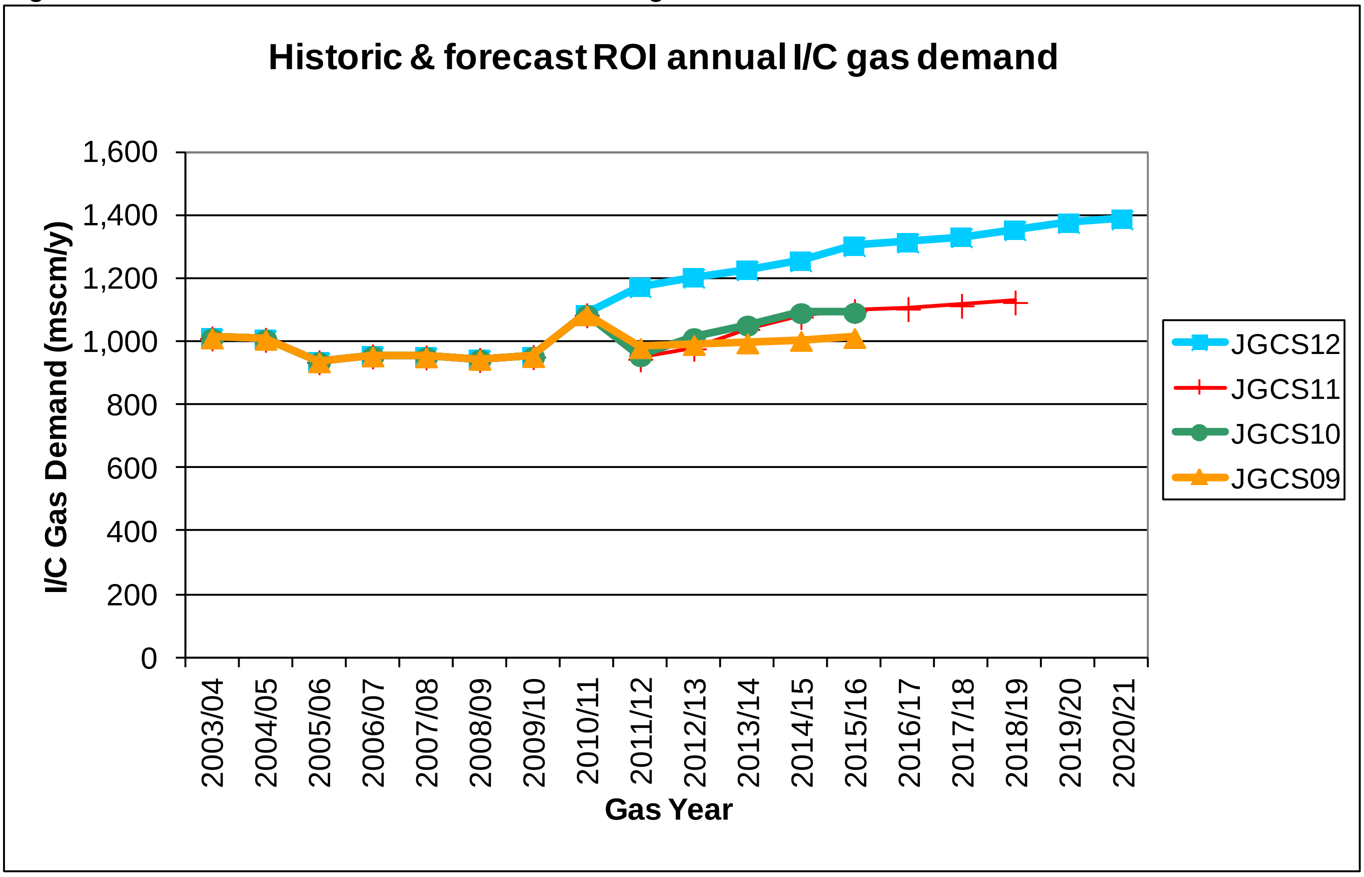
This year's JGCS includes estimation in the I/C forecast figures for the gas demand for process use gas demand from CHP units. This has resulted in an increase in the forecast annual gas demand from 2011/12.

Table 3-9: Forecast annual gas demand of the ROI I/C sector[1]

	Unit	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Energy											
JGCS 12	TWh/y	12.2	13.3	13.5	13.8	14.0	14.2	14.4	14.7	14.9	15.1
VOLUME											
JGCS 12	mscm/y	1,116	1,203	1,227	1,255	1,303	1,315	1,331	1,354	1,376	1,388
JGCS 11	mscm/y	947	980	1,041	1,080	1,099	1,106	1,116	1,126	1,139	
JGCS 10	mscm/y	956	1,014	1,053	1,093	1,094	1,093	1,094	1,096		
JGCS 09	mscm/y	982	992	997	1,005	1,014					

[1] *The I/C sector gas demand forecast for 2012 JGCS includes an estimation for CHP units which also employ gas for process use*

Figure 3-15: Historical and forecast ROI annual I/C gas demand



The annual I/C gas demand is forecast to continue to grow in 2012/13 assisted by continued export led growth and a slowdown in the reduction of smaller I/C loads. Relatively steady growth is anticipated to occur from 2012/13 to 2017/18 with slightly higher growth from 2017/18 onwards. Growth figures are expected to be slightly offset by increases in energy efficiency measures.

Most of the I/C energy efficiency savings outlined in the National Energy Efficiency Action Plan (NEEAP) for Ireland, are assumed to take place post 2016. The JGCS 2012 assumes annual energy efficiency savings of 33 GWh/y up to 2015/16, and 133GWh/yr from 2015/16 onwards (equivalent to 0.3% and 1.1% respectively of annual I/C gas demand in 2010/11). The analysis assumed that 50% of the energy savings targets outlined in the NEEAP document will be achieved. The assumptions in relation to the I/C energy efficiency savings are explained in more detail in Appendix 4.

The latest JGCS forecast of I/C demand shows an increase in demand in 2010/11 and 2011/12 over previous forecasts due to the use of process gas by CHP units. The growth rate presented in 2012 JGCS is in line with previous forecasts.

3.4.6 *ROI Residential gas demand*

The growth in residential gas demand will be impacted by both the number of new residential customers and also the government's planned energy efficiency initiatives. The forecast of new residential gas connections is based on new connections forecast from BGN. The forecast makes an allowance for the number of existing dwellings which will convert to gas for their central heating and ancillary needs over the forecast period.

Table 3-10: 'New Build' & Existing Housing Connection numbers

	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
Assumed New Build Connections	1,200	1,200	1,650	3,825	4,500	4,500	4,500	5,500	6,000	6,500
Existing Houses[1]	3,630	3,833	3,753	3,393	3,281	3,281	3,281	3,117	3,035	2,952
Total New Connections	4,830	5,033	5,403	7,218	7,781	7,781	7,781	8,617	9,035	9,452

[1] Existing houses which are newly connected to the gas network.

The forecast assumes that the number of new residential connections will continue to decline in 2011/12, given the current state of the economy and the construction sector in particular. 'New Build' residential connections are therefore taken as being 1,200 in 2011/12 before climbing again to 6,500 p.a. by the end of the period.

The incremental demand from each new connection is also expected to reduce over the period due to enhanced building regulations, which are designed to reduce the typical energy consumption of a new home by c. 40% of 2005/06 levels and is assumed to increase to 60% and take effect in 2012/13.[12]

The proposed standards for more efficient boilers (Home Energy Saving Scheme etc.) are designed to improve the energy efficiency for the existing housing stock. It is estimated these measures could lead to an annual reduction of -0.9% p.a. to the existing residential gas demand. The energy efficiency assumptions made in the JGCS forecast are based on the NEEAP and are described in more detail in Appendix 4.

Due to continued uncertainty surrounding the rollout and implementation of the energy efficiency initiatives for existing housing, it is assumed that the efficiency factor of new residential builds will increase from 40% in 2009/10 to 60% by 2011/12. The results indicate that total demand for the island may be circa 0.9GWh/d lower by 2019/20. See Section 3.5.7 for further information on the peak day demand analysis.

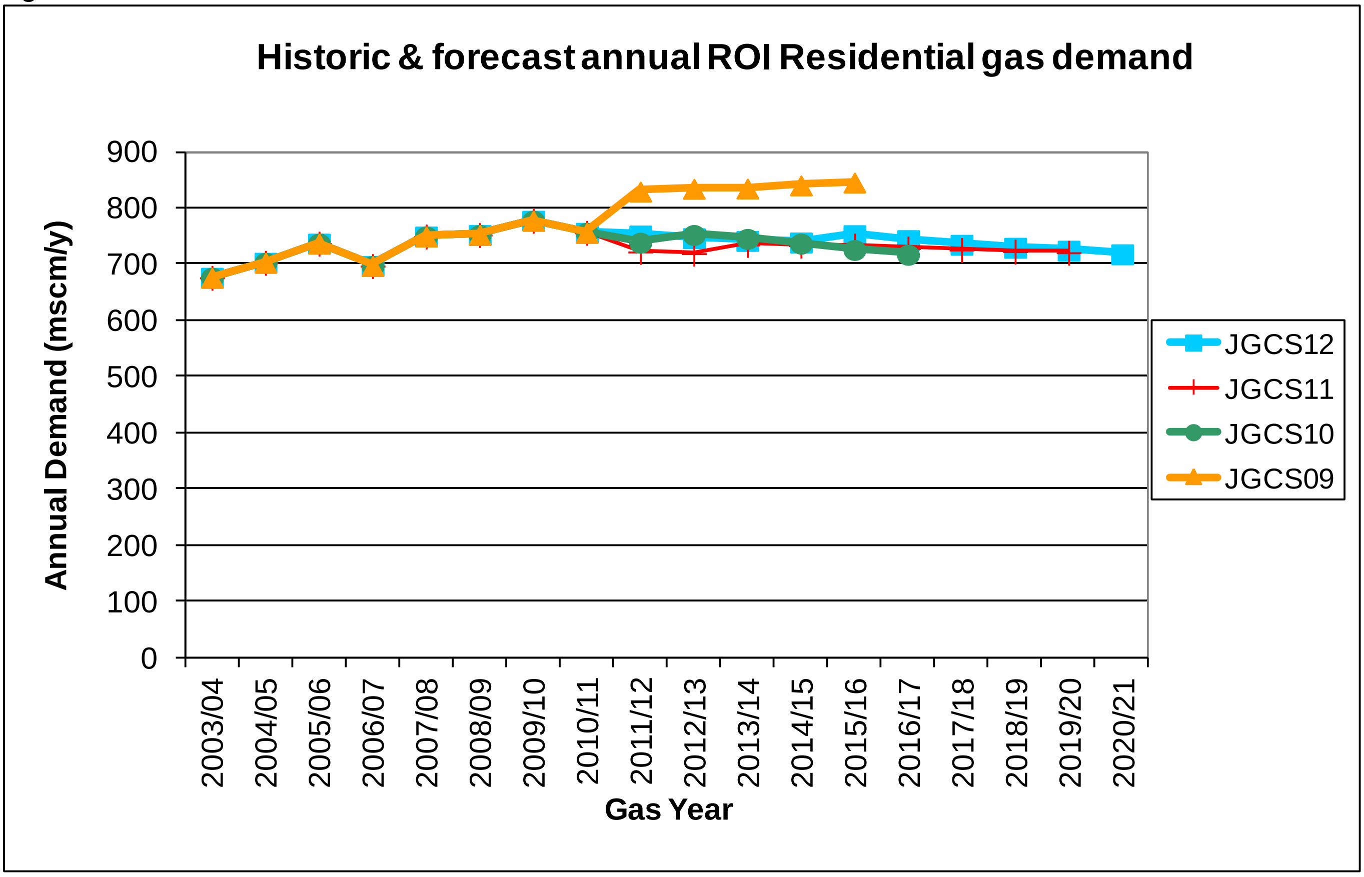
The JGCS residential annual demand forecast is summarised in Table 3.11 and illustrated in Fig. 3.16 together with the corresponding JGCS forecasts from previous years.

Table 3-11: Forecast Annual Gas Demand of the ROI Residential Sector

	Unit	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
ENERGY											
JGCS 12	TWh/y	7.1	8.2	8.2	8.1	8.1	8.0	8.0	7.9	7.9	7.8
VOLUME											
JGCS 12	mscm/y	648	748	743	740	753	745	736	731	726	719
JGCS 11	mscm/y	724	721	736	735	735	730	727	724	722	
JGCS 10	mscm/y	740	754	747	738	727	718	711	704		
JGCS 09	mscm/y	831	836	836	842	847					

12 These targets are based on requirements of the 2002 and 2010 Building Regulations respectively as noted in the NEEAP. The Gas Year 2012/13 has been used as it is presumed that the energy efficiency gains from the 2010 Building Regulation requirement would not be immediately evident.

Figure 3-16: Historic and Forecast ROI Annual Residential Gas Demand



The latest JGCS forecast anticipates an increase in the residential gas demand following the expected low annual demand of 2011/12. The forecasted demand to 2020/21 remains lower than the 2010/11 demand for all years. This decrease in residential gas demand is due to the slowdown in new connections, increased efficiencies and current economic conditions.

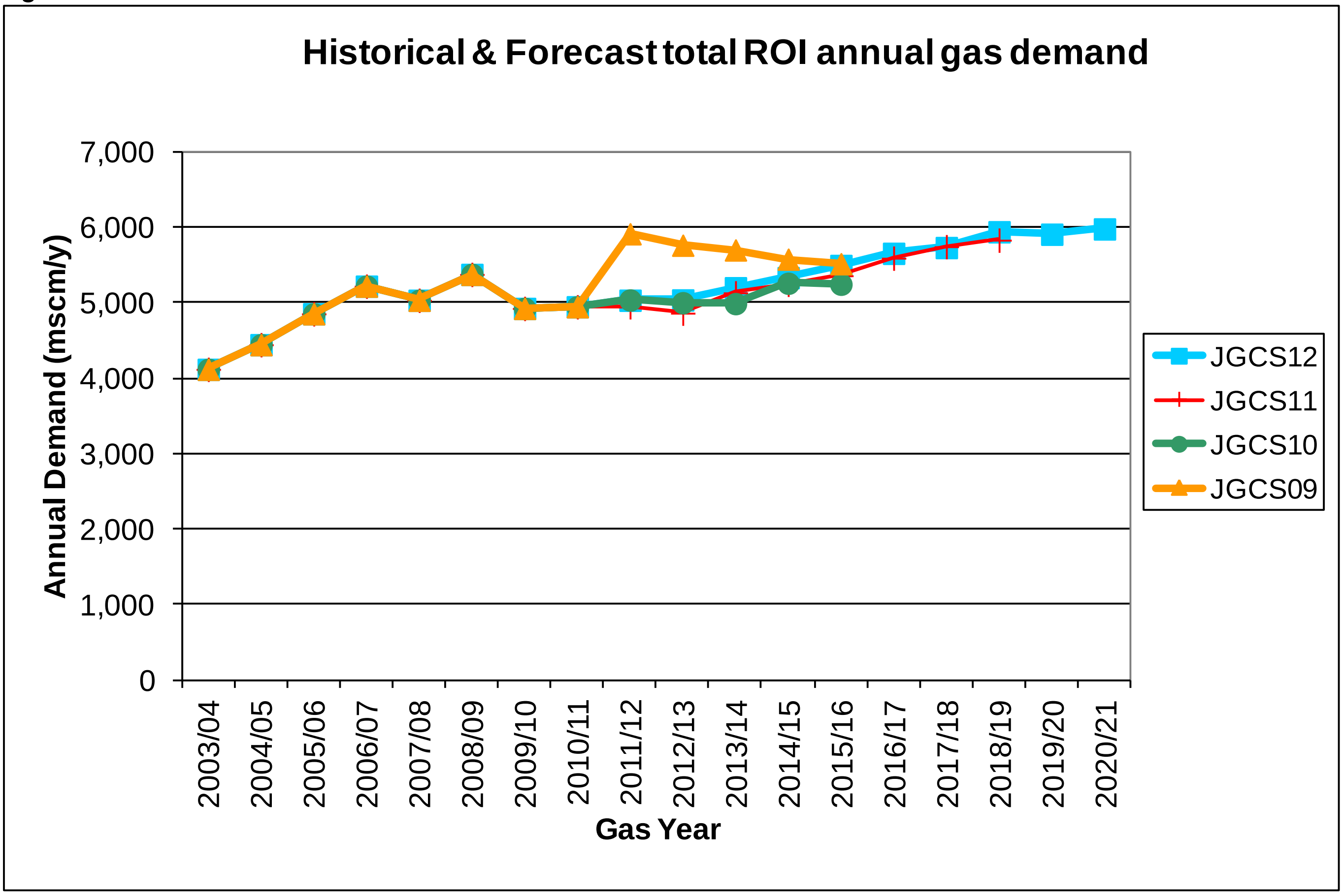
3.4.7 *Total ROI annual gas demand*

The forecast total ROI annual gas demand is summarised in Table 3.12 and illustrated in Fig. 3.17, together with the corresponding forecast published in previous versions of the JGCS. The total ROI annual gas demand is forecast to grow at an average rate of 2.9% p.a. over the period 2011/12 to 2020/21. The latest annual demand forecast figures for the ROI in the 2012 JGCS are slightly ahead of those presented in the 2011 JGCS from 2012/13 onwards due to a higher IC forecast demand and a slightly higher residential demand.

Table 3-12: Forecast Total ROI Annual Gas Demand

	Unit	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
ENERGY											
JGCS12	TWh/y	50.2	55.6	57.4	58.7	59.0	61.0	62.1	64.4	64.1	65.0
VOLUME											
JGCS 12	mscm/y	4,578	5,042	5,204	5,338	5,500	5,661	5,737	5,947	5,914	5,985
JGCS 11	mscm/y	4,952	4,867	5,137	5,250	5,364	5,597	5,749	5,836	5,889	
JGCS 10	mscm/y	5,041	5,005	4,994	5,264	5,251	5,413	5,443	5,714		
JGCS 09	mscm/y	5,920	5,769	5,706	5,583	5,523					

Figure 3-17: Historic & Forecast Total ROI Annual Gas Demand



3.4.8 *ROI Peak-day gas demand*

In addition to the forecast of total ROI annual demand, it is also necessary to produce a forecast of ROI peak-day demand in order to access the adequacy of the BGE transmission system. Two peak days are modelled as part of this process, a 1-in-50 winter peak day representing a severe winter peak day demand (similar to conditions experienced in January and December 2010) and an average year peak day representing an average winter peak day demand.

The ROI peak-day demand forecasts are summarised by sector in Appendix A, together with the corresponding sources of supply.

3.5 The NI Gas Demand Forecast

3.5.1 *NI gas demand forecasting methodology*

The NI shippers and power generators are required to provide an estimate of their future capacity requirements and commodity throughput, as part of the "Postalised" tariff arrangements. As part of the JGCS 2012, the postalised demand figures were reviewed by the distribution companies and updated to reflect their latest demand forecasts for the period modelled. Similarly demand forecasts for the power generation sector were reviewed by the power stations and updated to reflect their latest modelling forecasts.

The forecast NI annual demand is summarised is Table 3.13. The forecasts have been taken from information provided to the Utility Regulator by power generation and distribution system shippers in Northern Ireland. Overall demand is forecast to grow at an average of 1.62% per annum over the period modelled. A breakdown of the power and distribution sector is provided below.

Table 3-13: Forecast NI annual gas demand

	Unit	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
ENERGY											
Power	TWh/y	9.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Distribution	TWh/y	4.9	5.1	5.3	5.4	5.6	5.7	5.8	6.0	6.1	6.3
Total NI	TWh/y	14.8	15.9	16.1	16.3	16.5	16.6	16.7	16.9	17.0	17.2
VOLUME											
Power	mscm/y	893	984	984	984	984	984	984	984	984	984
Distribution	mscm/y	445	458	477	492	505	517	529	541	553	571
Total NI	mscm/y	1,338	1,442	1,461	1,476	1,489	1,501	1,513	1,525	1,537	1,555

The forecast for the Northern Ireland winter peak demand is discussed in section 3.5.2 below. Notably the winter peak forecasts include both firm and interruptible demand and also represent a simultaneous peak occurring across both the distribution demand and power generation sectors.

As such the total demand forecasts are high and represent a conservative modelling approach by testing the ability of the network to meet both firm and interruptible demand when both power and distribution sector are at peak demands.

Power Generation

Forecast figures were provided by the two gas fired power stations, Ballylumford and Coolkeeragh. The total power generation figures provided in Table 3-13 are the aggregated demand for the two sites. Figures provided were from the generators own demand modelling forecasts based on a number of assumptions: including the power stations' expected growth rates in electricity demand, the impact of planned generator units and the expected dispatch order under SEM. Forward commodity prices and the influence of other fuel sources were also included in the modelling inputs.

As table 3-13 outlines, gas demand within the power generation sector is forecast to increase from 9.9 TWh/y in 2011/12 to 10.9 TWh/y in 2012/13 and to remain relatively stable for the following period. This is a significant increase (10%) in the first year and is due to an increase from forecasts from Ballylumford (4.3 Twh/y in 2011/12 to 5.3 Twh/y in 2012/13). Coolkeeragh forecasts remain flat for the period modelled.

The actual flows to Ballylumford for the 2011/12 gas year provide a reference and are recorded as 4, 0 TWh/y which indicate that the forecast figure of 4.3 TWh/y for 2011/12 is appropriate. Compared to the 2011/12 actual recorded flows, the forecast figures of 5.3 Twh/y from 2012/13 onwards seem high, however when compared against actual demand from 2010/11 (5.9 Twh/y) the forecast figures for years 2012/13 onwards seem reasonable.

Such a high degree of variance reflects the uncertainty in forecasting future demands given a number of factors that impact gas demand. For example, flows to Ballylumford are down 32% in 2011/12 compared to 2010/11 due to a number of factors including increased generation from Kilroot due to lower coal prices, more efficient plant in ROI, overall electricity demand being lower, and a return to availability of the Moyle interconnector.

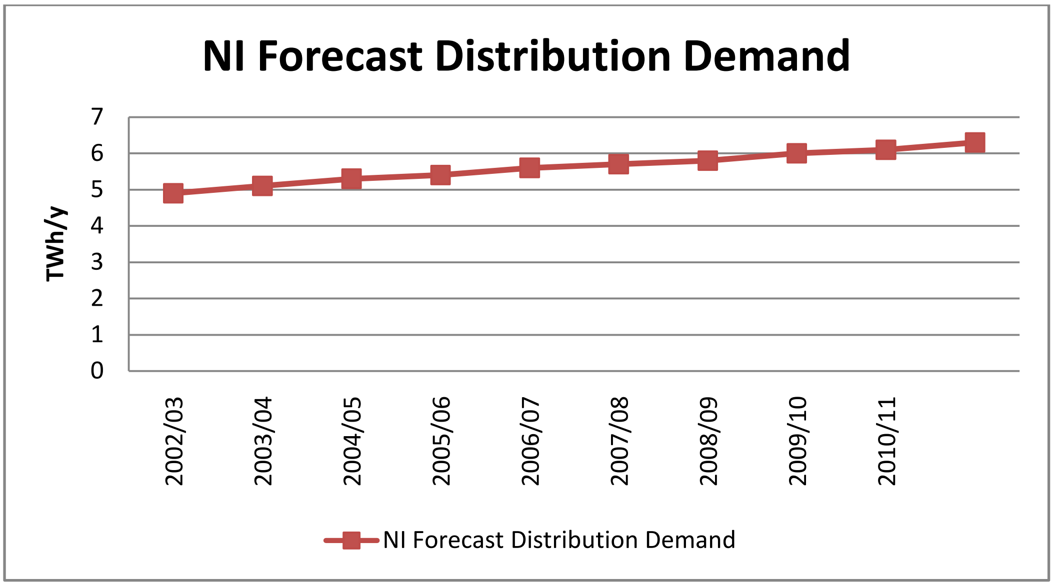
Distribution

Forecast figures were provided by the two gas distribution companies, Phoenix Natural Gas Ltd and Firmus Energy Ltd. The total distribution figures provided in Table 3-13 are the aggregated demand forecasts for both distribution companies. Again figures provided for the purposes of the JGCS were based on the distribution companies own modelling forecasts which incorporated the expected growth rates within the domestic and I/C sectors over the 10 years modelled.

Demand in the Northern Ireland distribution market is forecast to grow at an annual rate of 2.8% p.a. over the period modelled, depicted in Figure 3-18. The year-on-year increase reflects the distribution companies' expected growth rates within the domestic and I/C sectors. Forecast growth rates have also been revised to take into account prevailing economic conditions as well as the effect of energy efficiency measures across the sector.

The forecasted demand within the PNG licensed area is driven primarily by the continued growth of natural gas consumers, the majority of whom are domestic consumers. Firmus Energy has based their forecasts on their expected connections profile, circa 2,000 new connections per annum.

Figure 3-18: NI Forecast Distribution Demand



3.5.2 *NI Peak-day gas demand*

In addition to the forecast of total NI annual demand, it is also necessary to produce a forecast of NI peak-day demand in order to access the adequacy of the transmission system. Two peak days are modelled as part of this process, a 1-in-50 winter peak day representing a severe winter peak day demand and an average year peak day representing an average winter peak day demand.

The NI peak-day demand forecasts are summarised by sector in Appendix A, together with the corresponding source of supply. The figures are replicated in the tables 3-14 and 3-15 below:

As noted above, the winter peak forecasts include both firm and interruptible demand and also represent a simultaneous peak occurring across both the distribution demand and power generation sectors.

As such the total demand forecasts are high and represent a conservative modelling approach by testing the ability of the network to meet both firm and interruptible demand when both power and distribution sector are at peak demands.

Table 3-14: Forecast NI 1-in-50 winter peak day gas demand

	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
VOLUME	mscm/d									
Power	5.0	5.0	4.8	4.6	4.4	4.4	4.4	4.4	4.4	4.4
Distribution	3.0	3.1	3.2	3.3	3.4	3.5	3.6	3.7	3.8	3.9
Total NI	8.0	8.1	8.0	7.9	7.8	7.9	8.0	8.1	8.2	8.3

Table 3-15: Forecast NI average winter peak gas demand

	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21

VOLUME	mscm/d									
Power	4.5	4.4	4.3	4.1	3.9	3.9	3.9	3.9	3.9	3.9
Distribution	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.4	2.5	2.5
Total NI	6.4	6.5	6.4	6.3	6.2	6.2	6.3	6.3	6.4	6.5

Notably in this year's forecast figures there has been an increase in the total Northern Ireland peak-day forecast compared to previous years. The network analysis set out in chapter 5 demonstrates that this high Northern Ireland peak day demand, which represents a simultaneous peak across power and distribution sectors plus interruptible demand, has resulted in power station pressure requirements not being met.

Given these results, the RAs have provided an assessment of the peak day demand forecast below.

A summary of the 1-in-50 peak day figures in table 3-14 highlights the following:

- The total NI demand over the period modelled fluctuates around a peak day demand of 8.0 mscm
- Distribution peak day demand is forecast to increase by 0.1 mscm year-on-year for the period modelled starting from 3.0 mscm/day in 2011/12
- Powerstation peak day demand is forecast to reduce from 5.0 mscm in 2011/12 to 2015/16 and remain flat until 2020/21. The total powerstation breakdown is as follows:
    - Coolkeergah maintains a flat peak day demand profile over the forecast period
    - Ballylumford peak day demand falling from 2011/12 to 2014/15 and remaining flat from 15/16 onwards

Each of these points is discussed in turn below:

Total NI Forecast 1-in-50 Winter Peak Demand

For the total NI winter peak 1-in-50 demand, it is important to compare the forecast demands in Table 3-14 against actual winter peak demands that have been experienced. The Northern Ireland peak daily demand on SNIP experienced in the 2009/2010 and 2010/2011 severe winters was 6.7 mscm/day (7th January 2010) and 6.6 mscm/day respectively (8th, 21st, 22nd 23rd December). These figures represent the demand on the system during some of the most severe winter weather that has been experienced on record and as such demonstrate the robustness of the transmission system.

The total Northern Ireland winter peak 1-in-50 demand figures that have been modelled in this year's JCS 2012 are considerably higher than those experienced in the severe winter periods (by around 20%) experienced in the 2009/2010 and 2010/2011 winter periods. The forecast figures are also higher than the actual and forecast capacity bookings on the SNIP which are presented in Table 3-16 below. Again these figures have never been experienced. As noted above, the winter peak forecasts include both firm and interruptible demand and also represent a simultaneous peak occurring across both the distribution and power generation sectors.

Table 3-16: Firm capacity bookings on SNIP

	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
	mscm/d									
VOLUME	7.2[a]	7.3[a]	7.3[a]	7.4[a]	7.4[b]	7.4[b]	7.4[b]	7.4[b]	7.4[b]	7.8[b]

a: Booked Capacity; b: Forecast Capacity

It is also important to compare the actual winter peak demands experienced in the 2009/2010 and 2010/2011 with the average winter peak demands which are presented in table 3-15. The average winter-peak demands which are modelled in the 2012 JGCS are similar to the peak demands experienced in these winters; i.e. a maximum of 6.5 in the forecast figures compared to an actual maximum of 6.7 mscm/day. These figures show that the average winter peak days modelled in the JGCS represent a more realistic demand profile for a severe winter peak day, since these figures are in line with the peak demands that have been experienced. As set out in the network analysis the Northern Ireland transmission network is capable of meeting these demands.

NI Forecast Distribution 1-in 50 Winter Peak Demand

For the distribution peak day demand, the figures increase by 0.1 mscm year-on-year from 3.0 mscm/day in 2011/12. Again, the 3.0 mscm/day is high compared to the winter peak demands experienced in December 2010 where the total peak flows to the distribution sector were approximately 2.79 mscm/day.

The distribution companies have revised their peak day demand figures due to the demands experienced during the severe winter period of 2009/10 and 2010/11 together with an expected increase in peak day demand due to growth through new connections. However the revised figures seem high when compared to actual figures that have recently been experienced.

NI Forecast Power sector 1-in 50 Winter Peak Demand

For the powerstation peak day demand, the breakdown notes that Coolkeeragh have maintained a flat profile over the years modelled which is consistent with data provided for previous capacity statements and is appropriate for a base load station within the all-island electricity market. Total peak flows to Ballylumford are forecast at 36, 715[13] MWh/day (3.4 mscm/day) in 2011/12 and 2012/13 and are forecast to reduce to 29,307 MWh/day (2.7 mscm/day) from 2015/16 onwards. This profile reflects additional new power generation coming available in the years 2013/14 and 2014/15 which is expected to lower Ballylumford's place in the merit order.

Summary

In summary the Utility Regulator is of the view that the probability of the forecast profile for NI total 1-in 50 winter peak demand occurring remains low. The winter peak demand profiles include interruptible and firm demand and also represent a simultaneous peak demand occurring across both the power sector and distribution sectors. That does not discount such a high demand from occurring since unforeseen circumstances could bring about such conditions. However a number of extreme events would need to happen for such a high demand to occur. If such a high demand does occur and pressure levels are not available to provide gas to the powerstations, then the transmission system operators have arrangements in place to address these circumstances such as 'flip-flop' and use of the SN pipeline. These arrangements are discussed further in section 5.6.1.

The demands that have been modelled for the average winter peak demand represents a more realistic demand profile for a severe winter peak day, since these figures are in line with the peak demands that have been experienced. As set out in the network analysis the Northern Ireland transmission network is capable of meeting these demands.

It may be a conservative approach to test the robustness of the system by modelling a simultaneous total peak demand (including interruptible) rather than modelling firm demand only. However for future capacity statements it may be more beneficial to consider how the data on the peak day is presented to ensure it is more beneficial to industry.

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13 The peak demand of 36, 715 MWh/day was Ballylumford's recorded peak gas demand in October 2011and includes interruptible.

4 Gas Supplies

4.1 Overview

The majority of the gas demand in Ireland and all gas demand in Northern Ireland are currently supplied with GB gas imports through the Moffat Entry Point, with the remainder being supplied from the Inch Entry Point with Kinsale production and storage gas.

In the short to medium term, between 92 and 95% of the Island's demand will continue to be met from GB imports through the Moffat Entry Point. This supply outlook may change significantly from 2015/16 and again from 2017/18 if a number of new supply projects come online. These are at various stages of development and include:

- The Corrib gas field off the West Coast is currently being developed by the Corrib Gas Partners (i.e. Shell (Operator), Statoil and Vermillion) and is expected to commence full commercial production in April 2015;
- Islandmagee Storage are looking into the commercial feasibility of developing salt-cavity gas storage in the Larne area in NI. For modelling purposes it is assumed the start date is 2017/18; and;
- Shannon LNG have indicated that 2017 is the earliest possible start date for commercial operation. For modelling purposes it is assumed the start date in 2017/18.

All of these projects have been included in the supply scenarios that have been modelled in this year's JGCS and are outlined in Section 4.2.

4.2 Sources of supply

4.2.1 *Indigenous production*

Kinsale Production

Production gas from the Kinsale Head gas field in the Celtic Sea was initially brought ashore at Inch in 1978. This was subsequently supplemented with production gas from two satellite fields, namely the Ballycotton and South West Lobe (SWL) gas fields (see Figure 4.1). The SWL gas field has since been depleted, and now operates as a seasonal gas storage facility.

In 2003 the adjacent Seven Heads gas field was tied into the offshore Kinsale infrastructure, and Seven Heads gas was brought ashore at Inch. Production gas from the Kinsale and Seven Heads gas field is now in decline, and is small relative to total demand and is being superseded by the gas storage operation.

Corrib Gas

It is anticipated that the main source of future indigenous ROI production will be the Corrib gas field, which is currently being developed by the Corrib Gas Partners (Shell E&P Ireland, Statoil and Vermillion). Work is nearing completion on the construction of the Bellanaboy terminal in Co. Mayo, which will process the gas from the Corrib field. At the Corrib field, five wells are completed and ready for production, while construction of the 83km long offshore pipeline was successfully completed during 2009.

The project's final stage, involves the construction of a 9 km pipeline between land-fall at Glenagad and the gas processing terminal at Bellanaboy. The Corrib developers have received the final planning consents and permits from An Bord Pleanála, the DCENR and the Department of the Environment, allowing the developers to proceed with the construction of the final stage of the onshore pipeline.

This pipeline will be routed through Sruwaddacon Bay, and will involve building a tunnel under the bay within which the pipe will be laid. Based on the current construction and commissioning schedule, the Corrib field is assumed to commence full export operations in April 2015.

Commercial production of Corrib gas will make a significant contribution to the island's security of supply situation. Corrib gas is expected to meet 24.4% of the forecast BGE system 1-in-50 peak-day demand, and 44.1% of the all island annual demand in 2015/16. Corrib will on average provide 42% of all island gas demand over the first 2 years of operation.

It is to be noted that Corrib have recently revised their assumptions regarding peak day flow capacity to slightly under 9 mscm/d for the first year and slightly over 8 mscm/d for the second year. This change is based on recent well data and, as presented in table 4.1, is a revision from the previous profile of 10 mscm/d for the first 3 years. The production profile declines over the seven year period to 56% of year 1 capacity.

The island's dependence on GB imports, and the Moffat Entry Point, will rise again as Corrib production declines, unless new sources of supply are brought on stream.

Table 4-1: Corrib Forecast Maximum Daily Supply Capacity

	Unit	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
JGCS 2012	mscm/d	8.9	8.1	7.0	7.0	6.7	5.9	5.0
JGCS 2011	mscm/d	10.0	10.0	10.0	8.1	6.8	5.3	4.4

4.2.2 *Moffat Entry Point (Interconnector Imports)*

Declining Kinsale production and rising gas demand led to the construction of the first BGE subsea interconnector (IC1) between Ireland and Scotland in 1993, which connects into the GB National Transmission System (NTS) at the Moffat Entry Point. A second subsea interconnector (IC2) was completed in 2002 to meet the projected increase in demand, and also supplies gas to the Isle of Man (IOM).

The IC1 system in Scotland is also used to supply gas to NI. The Scotland and Northern Ireland Pipeline (SNIP) subsea interconnector was completed in 1996 and connects into the IC1 system at Twynholm in Scotland. The SNIP currently supplies all of NI demand and is also used to supply gas to the town of Stranraer in Scotland which has a relatively small demand.

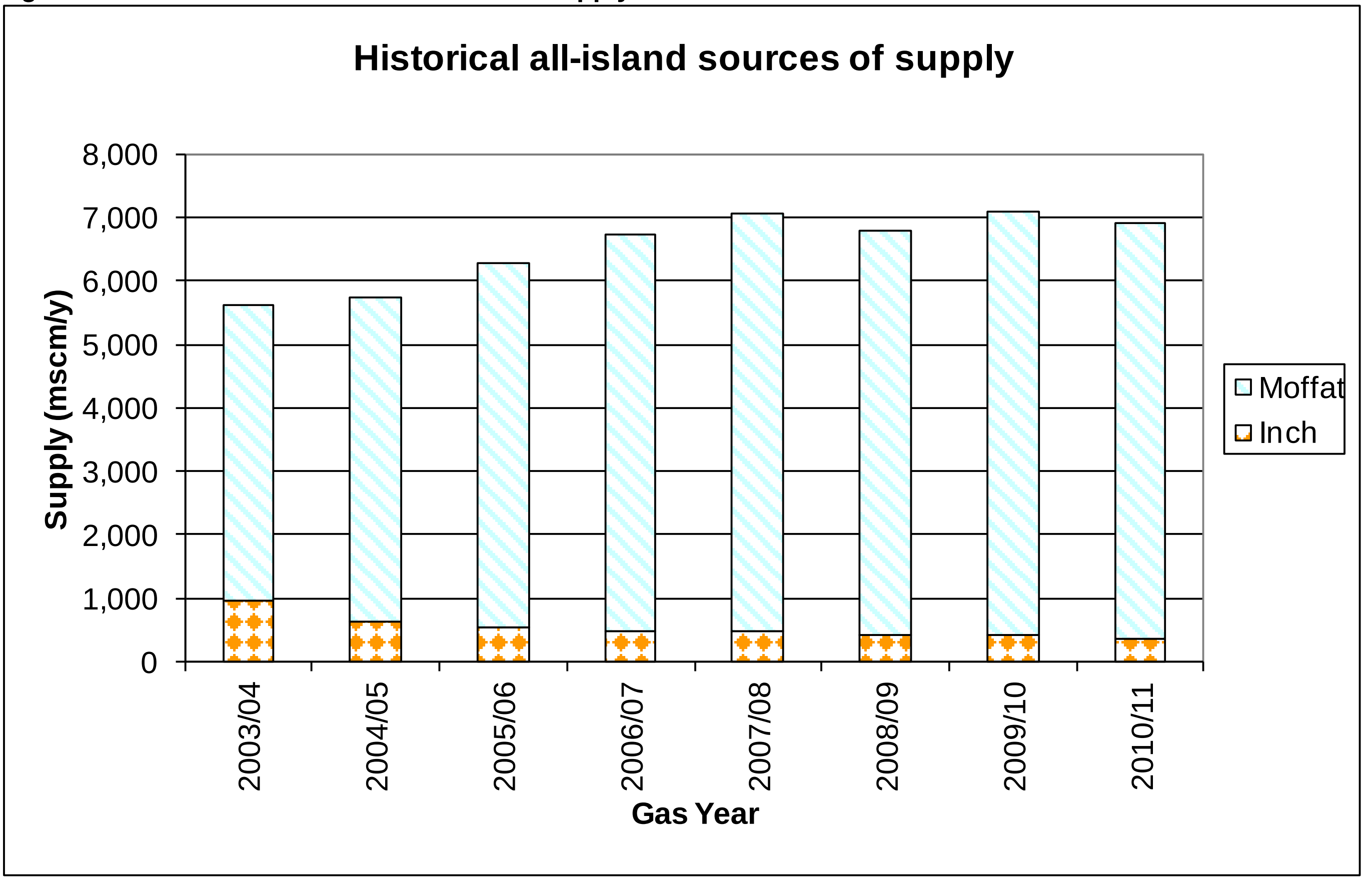
The first GB gas imports through the interconnector system in 1995 (IC1) were quite small; however they increased rapidly over time and imports through both IC1 and IC2 accounted for c.93.6% of ROI gas demand in 2010/11. Flows through the Moffat Entry Point, accounted for 95.1% of total All Island annual demand in 2010/11 (IC1, IC2 & SNIP). The historical breakdown of indigenous production and GB gas imports is given in Table 4.2 (for combined Ireland and Northern Ireland).

Table 4-2: Breakdown of the historical indigenous production and GB imports[1]

	Unit	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11
ENERGY									
Inch	GWh/y	9,705	6,397	5,451	4,976	4,772	4,259	4,128	3,765
Moffat	GWh/y	51,982	56,890	64,023	69,236	72,645	70,446	73,843	72,320
Total supply	GWh/y	61,687	63,287	69,474	74,212	77,417	74,705	77,971	76,086
VOLUME[2]									
Inch	mscm/y	932	614	523	478	455	404	392	356
Moffat	mscm/y	4,678	5,120	5,762	6,231	6,589	6,365	6,676	6,549
Total	mscm/y	4,391	4,122	4,448	4,858	7,044	6,769	7,068	6,905

[1]*Includes ROI, NI and IOM gas demand plus any Inch Exit to refill Kinsale Storage*
[2]*Volumes are derived from energy values by assuming a GCV of 40 MJ/m^3 & 37.5 MJ/m^3 for 2003/04 to 2006/07, 39.7 MJ/m^3 & 37.8 MJ/m^3 for 2007/08, 39.8 MJ/m^3 & 37.9 MJ/m^3 for 2008/09 & 09/10, and 39.8MJ/m^3 & 38.1 MJ/m^3 in 2010/11 for Moffat and Inch respectively*

Figure 4-2: Historical All-island Sources of Supply



4.3 Potential Gas Supply Sources

4.3.1. Production

A number of other potential gas prospects have also been identified in the Celtic Sea, which are currently being evaluated by a number of different developers for their technical and commercial viability. Further exploration continues to the North West of the Corrib gas field, and include the West Dooish and Cashel prospects. The commercial viability of these prospects have yet to be established.

Future development of unconventional gas resources may potentially contribute to the indigenous production of natural gas in Ireland and Northern Ireland. Private commercial bodies are currently investigating the potential development of shale gas resources in the North West region.

The position of all potential gas supply sources will continue to be kept under review and may be included in future JGCS publications if more firm data becomes available.

4.3.2. Gas Storage

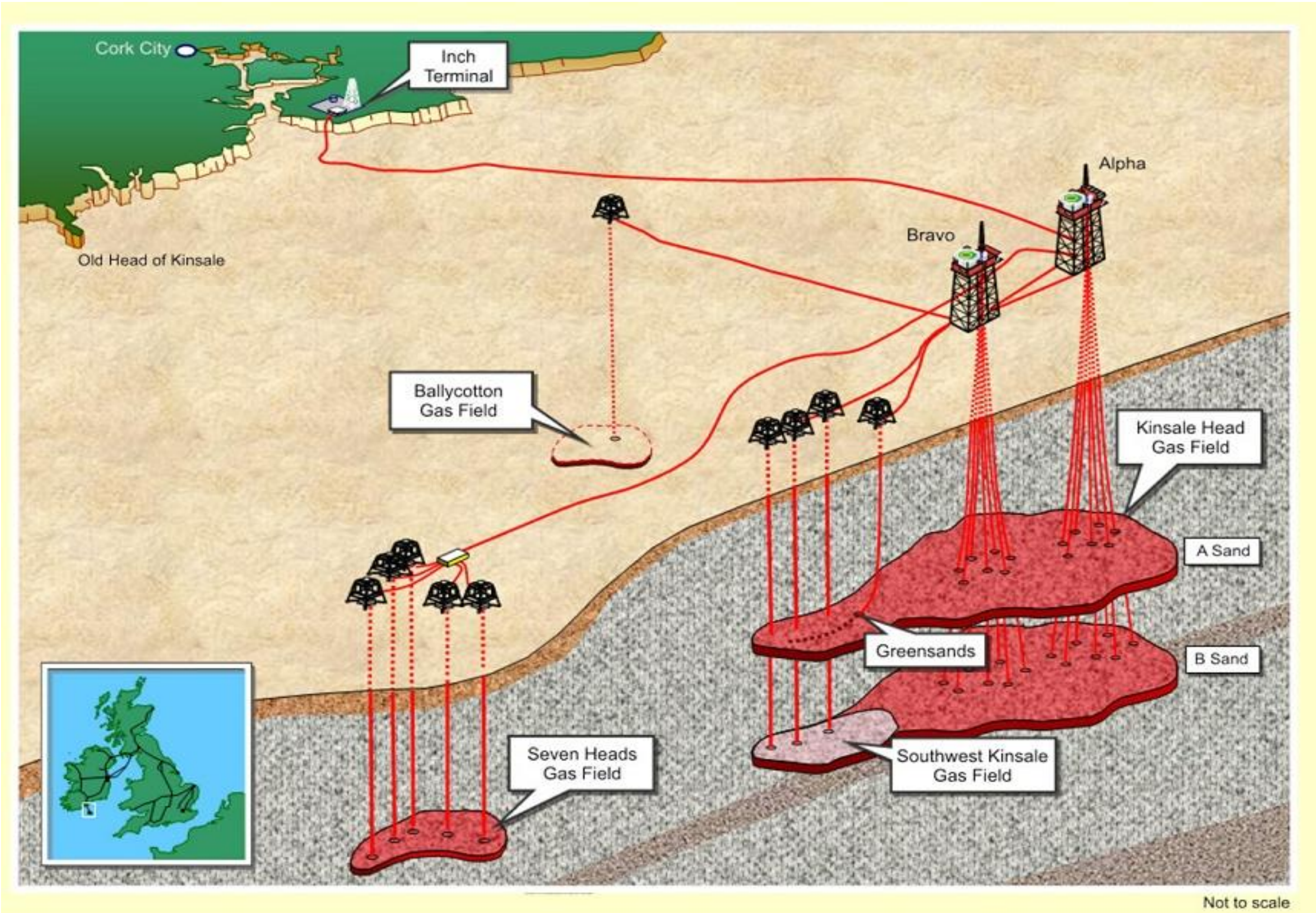
Kinsale Storage Facility

The Kinsale storage facility is operated by PSE Kinsale Energy Limited using the depleted Southwest Kinsale gas field. It currently has a working volume of c. 230 mscm (2,415.3 GWh) which is equivalent to about 5% of Ireland's annual gas consumption in 2011/12. It has a maximum withdrawal rate of 2.6 mscm/d (27.3 GWh/d) and a maximum injection rate of 1.7 mscm/d (17.85 GWh/d). It mainly operates as a seasonal storage facility, but can also accommodate within-day gas withdrawals and injections.

PSE Kinsale Energy Limited is presently determining the commercial feasibility of additional future development. It has been noted that the economic viability of the existing storage facility is linked to that of its gas production operations. The company has informed the CER that, as gas production gradually declines, the existing storage operations will not be economic on a standalone basis without further development. PSE has indicated that the existing storage operations may cease in 2013/14, thereafter a decommissioning period will begin during which injection operations will cease and the cushion gas will be drawn down from the wells in the years from 2013/14 to 2016/17. It is anticipated that in such a scenario gas will be supplied from the Inch Entry Point during both winter and summer periods.

PSE has also indicated that the storage activities may continue subject to market conditions and this possibility is also included in the JGCS scenarios. The supply scenarios used in the JGCS 2012 are detailed in Section 5.2.

Figure 4-1: Kinsale Gas Field



Source: PSE Kinsale Energy

Larne salt-cavity Storage

Islandmagee Gas Storage Ltd are currently progressing a project to develop a salt-cavity gas storage facility in the Larne Lough area of NI.

Islandmagee Storage is a consortium of Infrastrata plc, Moyle Energy Investments Ltd and BP Gas Marketing Ltd., and is looking to develop a 5,514 GWh (500 mscm) salt-cavity gas storage facility underneath Larne Lough, with a maximum withdrawal rate of 243 GWh/d (22.0 mscm/d) and injection rate of 132 GWh/d (12.0 mscm/d); and

Islandmagee Storage received planning permission for the storage facility and was granted a licence to store gas in October 2012. The consortium is continuing to progress the project including plans for the drilling of a test borehole. The Islandmagee storage developers have indicated 2017/18 as a possible start date for commercial operation.

The North East Storage project commented on in previous JGCS publications has failed to identify suitable salt layers at the proposed site. The consortium of Bord Gáis Energy and Storengy have decided not to progress further with the project.

4.3.1 *Liquefied Natural Gas*

Shannon LNG have indicated that 2017 is the earliest possible start date for commercial operation should the project proceed. Shannon LNG has received planning permission for both its proposed LNG terminal near Ballylongford in Co. Kerry, and for the associated transmission pipeline that will deliver the gas into the ROI transmission system. Shannon LNG are currently awaiting clarity on the application of gas transmission tariffs and a number of other considerations. Shannon LNG is considering such commercial issues prior to making a final decision to proceed.

It has been indicated that the terminal would be developed on a phased basis:

- Phase I will involve the construction of LNG storage tanks, and re-gasification facilities with a maximum export capacity of up to 127.0 GWh/d (11.3 mscm/d); and
- The LNG terminal has been designed to accommodate two additional expansion phases at a later date. The maximum send out for the two subsequent phases are noted as 191.1 GWh/d (17.0 mscm/d) and 314.7 GWh/d (28.3 mscm/d).

5 Network analysis

5.1 Introduction

As detailed in chapter 4 of this statement, the continuation of an existing supply source and the commencement of the proposed supply projects on the island remains uncertain[14];

- PSE KEL has indicated the continuation of current Inch storage operations post 2013/14 is subject to 'favourable' market conditions, with the potential for total cessation of Inch supplies after 2016/17.

  Existing Inch storage operations may cease in 2013/14, followed by a 3 year 'blow-down' phase when Inch supply is expected to comprise of production and cushion gas and total cessation of Inch supply after 2016/17.

- Shannon LNG has indicated the earliest possible start date for commercial operation at their proposed LNG terminal is 2017.

- The Larne storage developer, Islandmagee Storage Ltd, continue to progress plans regarding their salt cavity storage project. The planned start date for commercial operations is October 2017. The other Larne storage developer, North East Storage, have recently announced they will not be proceeding with their proposed storage project.

Currently the Corrib field is the only prospective new supply source in the medium term, with first commercial gas supplies expected in 2015/2016. Corrib is anticipated to meet approximately 33% of the ROI's peak day gas demand in its 1st year of production, however, Corrib production declines relatively quickly, when it will meet approximately 20% of the ROI's peak day gas demand in 2020/21 (year 6 of production).

The Moffat Entry Point and Interconnectors will continue to meet over 95% of the Island's gas supply requirement until Corrib commences production and may revert to this level of dependency post Corrib's peak production period, should Inch cease and no other future supply sources materialise.

5.2 Supply Scenarios

This year's JGCS includes four supply scenarios, to assess the range of outcomes associated with the timing of the various proposed supply projects. The four scenarios are summarised in table 5.1 with their corresponding merit orders (agreed by the CER & NIAUR) in table 5.2.

Corrib supply is assumed to commence in April 2015 in all four supply scenarios. Scenario 1 assesses the impact of Inch supply ceasing, whereas Scenario 2 assesses the impact of Inch continuing. Scenario 3 and 4 examines the impact of new supply sources, Larne Storage and Shannon LNG respectively. The balance of supply is assumed to be met by GB imports via the Moffat Entry Point in all scenarios. Two sensitivities regarding Corrib's start date were also included; Corrib supply commencing from October '14 (in time for winter 2014/15) and October '16 (2016/17).

Table 5-1: Summary of Supply Scenarios

Supply Source	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Inch	Until 2016/17	Available all years	Available all years	Available all years
Corrib	Start April '15[1]	Start April '15	Start April '15	Start April '15
Larne	Unavailable	Unavailable	Start October '17	Unavailable
Shannon	Unavailable	Unavailable	Unavailable	Start October '17

[1] Also includes sensitivities for Corrib commencing from 2014/15 and 2016/17

[14] In order to complete the detailed analysis and network modelling required to produce this document, the supply scenarios were defined in May 2012, based on the most up to date information at that time.

Table 5-2: Summary of Supply Source Dispatch Order for each Scenario

Despatch Order	Scenario 1	Scenario 2	Scenario 3	Scenario 4
1	Corrib	Corrib	Corrib	Corrib
2	Inch	Inch	Inch	Inch
3	Moffat	Moffat	Larne	Shannon
4	n/a	n/a	Moffat	Moffat

It should again be emphasised that the various supply merit orders have been assumed solely for demand/supply modeling and network analysis purposes. The actual order in which supplies will be despatched will be determined by shipper nominations and the commercial arrangements between shippers, transporters and producers/suppliers at the various Entry Points.

5.3 Transmission network capacity modelling

5.3.1 *Transmission network capacity modelling*

The purpose of hydraulic network modelling undertaken for this statement is to test the adequacy of the existing all-island transmission network for a forecast demand under a number of supply scenarios, establishing where pressures are outside acceptable assumed operational boundaries or where there is insufficient capacity to transport the necessary gas.

In order to assess the system on days of different demand pattern three demand type days were analysed for each supply scenario over a 10 year period from 2011/12 – 2020/21 inclusive:

- 1-in-50 year winter peak day
- Average year winter peak day
- Average year summer minimum day

These demand days, which are generated from the gas demand forecast, have been chosen as they represent the maximum and minimum flow conditions on the transmission system. In addition to this, with respect to storage, these demand days represent the best case scenario regarding maximum possible withdrawal rates on peak days and maximum possible injection rates on summer minimum days.

Modelling was carried out using "PipelineStudio®", simulation software which was configured to analyse the transient 24 hour demand cycle over a minimum period of three days to obtain consistent steady results (see Appendix 2 for more details of the network analysis modelling).

As per previous years, the ability of the all-island transmission system to accommodate the forecast gas demand requirements was validated against the following criteria:

- Maintaining the assumed minimum and maximum operating pressures at key points on the transmission systems, including:
    - Minimum of 55 barg at the Dublin City Gates (Abbotstown and Brownsbarn);
    - Minimum of 45 barg at Ballyveelish (for Waterford area)

- Minimum of 40 barg north of Midleton compressor station;
- Minimum of 30 barg at Coolkeeragh (Derry ~Londonderry);
- Minimum of 35 barg on the South North Pipeline (SNP);
- Minimum of 56 barg at the inlet to Twynholm; *and*
- Not to exceed the Maximum Operating Pressure (MOP) of the onshore transmission systems, currently 70 barg in Ireland and 75 barg in NI;

▪ Ensuring gas velocities do not exceed their design range of 10 – 12 m/s; *and*

▪ Operating the compressor stations within their performance envelopes.

5.3.2 *Beattock Compressor Station Analysis & Moffat Entry Point*

In this year's analysis there have been a number of changes to underlying assumptions regarding Moffat. These changes have had a significant impact on the results of the analysis. It is therefore important that these changes are outlined both at a high level and in detail for both the non-technical and technical readers.

The first of these changes is that the technical capacity of the Moffat entry point has reduced from 32mscmd to 31mscmd for the period 2012/13 to 2014/15 inclusive. This is in response to refinements in assumptions based on actual operating experience in the periods of high flow in 2010. The assumptions are discussed further below.

The second change is that a lower Anticipated Normal Operating Pressure (ANOP) is assumed to prevail on the National Grid side at Moffat from 2015/16 onwards. In the past St Fergus (near Aberdeen) supplied a large proportion of the GB supply, this led to higher prevailing pressures in the Moffat region. The amount of supply from St. Fergus has been declining and thus the prevailing pressures in the Moffat Region would tend to decline. In carrying out this year's analysis the RAs took the view that it would be prudent to reflect this new assumption in the modelling form 2015/16 onwards. The assumptions regarding the ANOP are discussed further below.

Change in Capacity 2012/13 to 2014/15

Previous capacity statements indicated that the theoretical technical capacity of the Moffat Entry Point, 32 mscmd, was subject to the capacity of Beattock Compressor Station, based on a number of operating assumptions;

- Station inlet pressure of 47 barg (from the National Grid (GB) NTS)
- Station discharge pressure of 85 barg
- Gas inlet temperature of 15°C
- Three compressor units operating in 'series mode' (with a fourth unit on standby)

The technical capacity of the Moffat Entry Point was revised subsequent to the publication of last year's statement, in response to extensive desktop studies which were undertaken during 2011. These studies involved a detailed analysis of the southwest Scotland onshore system (SWSOS) during the peak demand events experienced in December 2010, resulting in a revision to the assumptions associated with Beattock compressor station and the station's technical capacity.

The capacity of Beattock Compressor and the Moffat Entry Point is now declared as 31 mscmd based on;

- Station inlet pressure of 47 barg (from the National Grid (GB) NTS)
- A discharge pressure of 76.6 barg,
- A gas inlet temperature of 10°C
- Three compressor units operating in 'parallel mode' (with one on standby).

BGN have advised the station will operate in parallel mode, in order to accommodate the range of within-day flows resulting from nominations and renominations, and, the gas temperature is more likely to be of the order of 10°C on a winter peak day than the previously assumed 15°C[15]. This will allow higher flows though Beattock but will reduce the available discharge pressure.

The revision to these assumptions combined with advancements in network analysis has resulted in a change to the calculated discharge pressures at Beattock. The aforementioned studies combined with performance testing at the compressor stations in southwest Scotland have enhanced BGN's ability to predict the behaviour of the SWSOS (including the compressor stations) above historic peak flows.

Previously 85 barg was taken as the discharge pressure in all cases, whereas Beattock's discharge pressure is now determined by desktop analysis based on the compressor performance characteristics, inlet pressure and temperature conditions and forecasted Moffat flows, for parallel mode of operation (and such that pressures do not exceed 85 barg).

Desktop analysis indicating discharge pressures at Beattock, which are less than 85 barg, imply lower pressures at Twynholm and Brighouse Bay than those determined in previous years. It should be noted however, while pressures are less than previous years, they still exceed the contractual minimum at Twynholm, 56 barg, and minimum design limit at Brighouse Bay, 52 barg.

Change in Capacity 2015/16 onwards

As noted in above, one of the primary determinants of the capacity at the Moffat Entry Point is the pressures available from the National Grid NTS at Moffat. The current technical capacity of 31 mscmd is based on an ANOP pressure of 47 barg. However, actual pressures approaching 45 barg have been observed on various occasions over the past 24 months. National Grid is contractually required to provide gas at a minimum pressure of 42.5 barg (for flows up to 26 mscmd), under the existing Pressure Maintenance Agreement (PMA). Lower pressures at Moffat imply a lower technical capacity for the Moffat Entry Point.

Gaslink and BGN have engaged with National Gird regarding Moffat NTS pressures, and have been advised that the occurrence of pressures below the 47 barg are isolated 'within day' incidents, and that it is prudent to continue assuming the ANOP pressure of 47 barg for the current year and following 3 years, for Network Planning purposes.

National Grid has indicated that the Moffat Exit Point is classified as a null point[16] from a network analysis point of view on the GB NTS, due to the change in GB flow patterns. GB gas supplies from the north (St. Fergus) have substantially reduced over the last 10 years, due to the decline in UK Continental Shelf (CS) production and increased from the south, due to the commissioning of the LNG terminals at Milford Haven and the Isle of Grain combined with additional Norwegian Imports at Easington.

In response to the consultation with National Grid, BGN will be assuming the ANOP Moffat NTS pressure of 47 barg until 2014/15 (inclusive) and a lower pressure of 45 barg from 2015/16. This assumption will be reviewed on an ongoing basis.

Network Analysis has determined the technical capacity of the Moffat Entry Point is 29 mscmd, based on an inlet pressure of 45 barg at the Moffat Exit Point on the GB NTS. Consequently, the capacity of the Moffat Entry point is assumed to reduce from 31 mscmd to 29 mscmd for all years from 2015/16 (inclusive).

[15] The Gaslink Winter Outlook 2011/12 and Gaslink NDS 2011/12 provide a detailed explanation of these changes regarding Beattock compressor station and the Moffat Entry Point.

[16] A null point is a term used by network analysts to describe an offtake point on a feeder where typically all flows will be towards that point and there are no flows past the point. In the case of Moffat this means that the offtake is typically fed simultaneously from both the north and the south and hence there is no NTS flow past the point from North to South (or South to North).

5.4 Transmission network capacity modelling

There are 2 AGIs at Gormanston. Gormanston Phase I AGI links IC2 to the rest of the Ireland transmission system. Gormanston Phase II AGI links IC2 to the Northern Ireland transmission system (through the South North Pipeline). The two systems are operated separately and have different underlying operating regimes. Additional pressure and flow control (including metering) would be required at Gormanston to physically connect the ROI and NI transmission systems at Gormanston.

For the relevant years under review it is assumed that the necessary operational and commercial requirements are in place as part of the Common Arrangements for Gas (CAG) project to facilitate the potential transport of surplus gas from NI (as a result of Larne storage gas withdrawals) into Ireland, and transport surplus gas from Ireland into NI, if required.

The potential system configurations at the Gormanston AGIs, referred to as 'CAG Open' and 'CAG Closed', are detailed in Appendix 3.

BGN have noted that the necessary operational requirements to facilitate flows between the two jurisdictions (CAG Open configuration) would involve system modifications. Additional metering, flow control and pressure control equipment would be required. Modifications may also be required at Twynholm, Carrickfergus, Brighouse Bay and potentially other network locations. Detailed studies would be required to determine the scale and cost of modifications at each of these locations.

5.5 Entry Point Assumptions

The main Entry Point assumptions in terms of gas pressures, Gross Calorific Value (GCV) and flow profiles are summarised in Table 5- which shows both the contractual minimum pressure and the pressure assumed for network analysis.

Table 5-3: Summary of Main Entry Point Assumptions

	Unit	Moffat	Inch	Corrib	Larne	Shannon
PRESSURE						
Contractual	barg	42.5[1]	30.0	Up to 85	N/A	N/A
Assumed	barg	47.0/45.0[2]	30.0	Up to 85	Up to MOP[3]	Up to MOP[3]
OTHER						
GCV	MJ/m^3	39.77	37.50	37.50	39.77	40.46
Flow profile[4]		Flat	Flat	Flat	Flat	Flat
Max Supply[5]	mscmd	31.0	3.2	8.9	22.0	11.3

[1]Contractual pressure up to 26mscmd under the existing Pressure Maintenance Agreement (PMA)
[2]ANOP of 47 barg assumed up to and including 2014/15, reducing to 45 barg thereafter (see section 5.6.3.1)
[3]GCV of Celtic Sea production gas.
[4]Flat flow profile assumes the uniform delivery of gas at the Entry Point
[5]The maximum capacity for each supply source over the forecast period.

Currently, under the Inch Connected Systems Agreement (CSA) PSE Kinsale Energy is required to provide a minimum pressure of 30 barg at Inch.

Contractually, the Corrib operator will be required to provide up to 85 barg at Bellanaboy. Modelling assumes that Corrib gas can enter the ringmain at Cappagh South at a pressure no greater than 70 barg, consistent with the current ringmain MOP.

The SNIP and SNP currently have an MOP of 75 barg, but it is assumed that the SNIP and SNP MOPs are uprated to 85 barg coincident with the availability of Larne Storage. While there are currently no contractual arrangements in place with the proposed Larne gas storage project, it is assumed that it will be able to deliver gas up to 85 barg.

The daily flows through each Entry Point are assumed to follow a flat flow profile, with the diurnal swing in the demand profile being absorbed by the line-pack of the island's onshore transmission systems and the subsea Interconnector (IC) system and the SNIP. It should be noted, the actual within-day flows at the Moffat Entry Point follow a non-uniform profile as a consequence of shipper behaviour. Within-day nominations/renominations at the Moffat Entry point occur hour to hour throughout the gas day in response to changes in the downstream customer demand or market dynamics. This requires the TSO to flow gas in a non-uniform flow profile, i.e. stepped/swing profile in order to meet the required end of day quantity (EODQ).

Larne Storage is assumed to operate as seasonal gas storage facilities i.e. withdraw gas from storage during the winter period and inject gas into storage during the summer period. Shannon LNG is assumed to supply year-round.

It is currently unknown how gas flows will be profiled at the Entry Points for the proposed new sources of supply. Network modelling assumes a uniform flow profile for each of the Entry Points. Further network analysis would be required to assess the impact on the transmission networks, if non-uniform flow profiles were assumed at the various Entry Points.

5.6 Network Modelling Results

It is important to note, the results and conclusions of the network analysis detailed in this section are subject to a set of assumed demand, supply and network configuration conditions. Any departure from these conditions may lead to a change in pressure profiles and result in low pressure levels within the system.

5.6.1 *Summary of overall Modelling results*

The key observations from the network analysis undertaken for this year's statement are as follows;

- ***CAG***
  - The physical flow of gas between ROI and NI is subject (in part) to surplus supply being available in either of the two jurisdictions and the appropriate system modifications being in place. Analysis indicates that surplus supply is dependent on the development of new supply sources on the Island (Shannon LNG, Larne and/or new indigenous sources of supply).

- **Moffat**
  - Capacity limits at the Moffat Entry Point will be reached in 2014/15 and again in 2018/19 (and all subsequent years) should the forecasted 1-in-50 peak day demands occur and no new supply sources are developed.

  - Flows through the Moffat Entry Point on the 'Summer Minimum Day' for all years from 2015/16 are less than the minimum design limit of Beattock compressor station, 12 mscmd. The same issue arises on the winter peak days from 2018/19 in the Larne scenario. Investment may be required at Beattock compressor station to facilitate flows below the minimum design limit.

- **ROI Onshore Transmission System**
  - The southern part of the ROI transmission system may require reinforcement from 2018/19 if Inch supplies cease and no new supply sources are developed.

- **NI Onshore Transmission System**
  - A reduction in pressure levels are observed in the NI onshore transmission system on the 1-in-50 winter peak day between 2011/12 and 2014/15 which reduces the ability to meet powerstation

demand if Twynholm is the only Entry Point being utilised. Notably contractual pressure limits have not been breached.

- Re-routing some of NI gas requirement from Moffat through the ICs and the Gormanston (NI) Entry Point would resolve the low pressure levels in NI.
- Should low pressure levels occur, the current 'flip-flop' arrangements contained in PTL's network code would also allow the powerstations to continue to generate electricity. Under 'flip-flop' arrangements Ballylumford and Coolkeergah powerstations take it in turn to reduce gas nominations and switch to secondary fuels until pressures in the gas transmission system are restored.
- The availability of Larne Storage from 2017/18 would resolve the low pressure levels in later years.

5.6.2 *CAG Flows*

Table 5-4 summarises the inter-jurisdictional flows under a CAG regime, i.e. the physical flow of gas between the onshore ROI and onshore NI systems, as determined by the network analysis. The physical flow of gas between the two jurisdictions is subject to surplus supply being available and the appropriate system modifications being in place to facilitate such flows.

With the exception of the summer minimum day for 1 year (2015/16), ROI demand is equal to or greater than the daily supply capacity of Corrib, resulting in no surplus gas supplies. As detailed in table 5-4, surplus supply would be available on the summer minimum day if Shannon LNG proceeds and on both the 1-in-50 and average year winter peak days if Larne Storage proceeds. Therefore, the availability of surplus gas supplies in either jurisdiction is dependent on the development of new supply sources on the island as a whole (Shannon LNG and/or Larne Storage and/or new indigenous sources of supply).

Network analysis also determined pressures in the SNP are not sufficiently high to allow for the transport of Moffat gas to the ROI via the SNIP and SNP.

Table 5-4: Inter-jurisdictional flows

	1-in-50 Peak Day	Average Year Peak Day	Summer Minimum Day
Scenario 1	No Scope[1]	No Scope[1]	2015/16 only
Scenario 2	No Scope[1]	No Scope[1]	No Scope[1]
Scenario 3[3]	2018/19 to 2020/21	2018/19 to 2020/21	No Scope[2]
Scenario 4	No Scope[1]	No Scope[1]	2017/18 to 2020/21

[1] There is no surplus supply in the ROI jurisdiction available for transportation to NI and pressures in the SNP (north of Gormanston) are not sufficient to transport gas to the ROI.
[2] There is no surplus supply in NI and pressures in the SNP (north of Gormanston) are not sufficient to transport gas to the ROI.
[3] In addition to Larne gas being transported to the ROI via the SNP, it is assumed Larne gas would also be transported to the ROI via the SNIP (reverse flow) and Interconnector system.

It should be noted that while appropriate system modifications may be completed to facilitate inter-jurisdictional flows, the commercial requirement for such modifications would depend on shippers wishing to nominate at an Entry Point(s) in the neighbouring jurisdiction and the capacity being available at the respective Entry Point (i.e. surplus supply).

5.6.3 *Moffat Entry Point*

5.6.3.1 Moffat Entry Point Capacity

Last year's JGCS noted the capacity limits of the Moffat Entry Point will be approached over the coming winters and will be reached in 2013/14, should forecasted peak demands occur and existing Inch storage operations cease in 2012/13. The analysis undertaken for this year's JGCS indicate the same capacity constraint will occur, albeit 1 year later in 2014/15, assuming existing Inch storage operations cease in 2013/14. This constraint is assumed to arise again in 2018/19 and all subsequent years, assuming no new supply sources materialise and Inch supplies have ceased.

The ongoing presence of non-uniform (stepped/swing) flow profiles at the Moffat Entry Point increases the likelihood of reaching capacity limits before 2014/15. As noted in section 5.5, non-uniform flow profiles at the Moffat Entry Point are a consequence of shipper nominations/re-nominations. The amount of system flexibility available to accommodate nominations/renominations on the winter peak days would be very limited and it is likely capacity limits will be reached.

The continuation of existing Inch storage operations would reduce the forecasted peak day flows at the Moffat Entry Point. Consequently capacity limits would not be reached, but approached in 2014/15, 2019/20 and 2020/21, with little or no system flexibility to accommodate renominations. An additional supply or demand side response would still be required to resolve the potential capacity constraint at Moffat, assuming current Inch storage withdrawal rates.

The advent of new supply sources, Shannon LNG, Larne Storage and/or new indigenous sources of supply would resolve the capacity constraint at Moffat in the later years, i.e. from 2018/19, assuming supplies are nominated from these entry points on the peak day. Table 5-5 details the level of Moffat capacity being utilised for the 1-in-50 peak day flows for each scenario.

Table 5-5: Inter-jurisdictional flows

	11/ 12	12/ 13	13/ 14	14/ 15	15/ 16	16/ 17	17/ 18	18/ 19	19/ 20	20/ 21
Scenario 1	98.5%	95.0%	97.2%	102.5%	86.9%	92.4%	99.5%	100.7%	103.1%	107.4%
Scenario 2	98.5%	95.0%	97.2%	98.3%	80.2%	84.5%	90.0%	91.4%	93.9%	98.3%
Scenario 3	98.5%	95.0%	97.2%	98.3%	80.2%	84.5%	69.5%	56.8%	19.6%	25.1%
Scenario 4	98.5%	95.0%	97.2%	98.3%	80.2%	84.5%	49.8%	51.2%	53.7%	58.1%

In summary, the development of new supply sources on the island will reduce the peak day flow requirement at the Moffat Entry Point, and remove the potential capacity constraint. However in the absence of new supply sources, the potential capacity constraint is likely to occur should 1-in-50 peak day demands materialise, requiring supply and/or demand side measures.

BGN and Gaslink continue to recommend the reinforcement of the single 50km section of transmission pipeline in southwest Scotland to address the potential capacity constraint at the Moffat Entry Point in the short to medium term and longer term, considering the absence of certainty regarding the other proposed supply projects. Reinforcing the 50km section of pipeline would allow for the maximum potential capacity of the IC system to be realised, ensuring the Island's energy requirements can be met post 2020.

The proposed Islandmagee gas storage facility would also reduce the peak day flow requirements at the Moffat Entry Point and address the potential low pressure levels in Northern Ireland.

In addition to the potential capacity constraint at the Moffat Entry Point on winter peak days, network analysis has also identified the potential for issues at Moffat when there is a requirement for small volumes of balancing gas supply. In addition to maximum limit (technical capacity), there is also a minimum flow limit associated with the Moffat Entry Point, which is the minimum design flow limit of Beattock compressor station of 12 mscmd.

Analysis indicates the balance of supply at the Moffat Entry Point is less than the minimum flow limit on the summer minimum days with the advent of Corrib (and/or Shannon LNG) and on winter peak days under the Larne scenario. Facilitating flows less than the current design limit of Beattock compressor station may require future investment.

5.6.3.2 Moffat Entry Point – NTS Pressures

As noted in the previous section, one of the primary determinants of the capacity at the Moffat Entry Point is the pressures available from the National Grid NTS at Moffat. The current technical capacity of 31 mscmd is based on an ANOP pressure of 47 barg. However, actual pressures approaching 45 barg have been observed on various occasions over the past 24 months. National Grid is contractually required to provide gas at a minimum pressure of 42.5 barg (for flows up to 26 mscmd), under the existing Pressure Maintenance Agreement (PMA). Lower pressures at Moffat imply a lower technical capacity for the Moffat Entry Point.

Gaslink and BGN have engaged with National Gird regarding Moffat NTS pressures, and have been advised that the occurrence of pressures below the 47 barg are isolated 'within day' incidents, and that it is prudent to continue assuming the ANOP pressure of 47 barg for the current year and following 3 years, for Network Planning purposes.

National Grid have indicated that the Moffat Exit Point is classified as a null pointfrom a network analysis point of view on the GB NTS, due to the change in GB flow patterns. GB gas supplies from the north (St. Fergus) have substantially reduced over the last 10 years, due to the decline in UK Continental Shelf (CS) production and increased from the south, due to the commissioning of the LNG terminals at Milford Haven and the Isle of Grain combined with additional Norwegian Imports at Easington.

In response to the consultation with National Grid, BGN will be assuming the ANOP Moffat NTS pressure of 47 barg until 2014/15 (inclusive) and a lower pressure of 45 barg from 2015/16. This assumption will be reviewed on an ongoing basis.

Network Analysis has determined the technical capacity of the Moffat Entry Point is 29 mscmd, based on an inlet pressure of 45 barg at the Moffat Exit Point on the GB NTS. Consequently, the capacity of the Moffat Entry point is assumed to reduce from 31 mscmd to 29 mscmd for all years from 2015/16 (inclusive).

5.6.4 *ROI & NI Onshore Transmission Systems*

Tables 5-6 and 5-7 summarises when pressure levels can and cannot meet demands in both the onshore ROI and onshore NI transmission systems based on the average winter peak day forecasts for each supply scenario. Green indicates when resultant pressures can meet demands whereas yellow indicates that resultant pressure levels cannot meet demands.

Network modelling indicates that system pressures in both the onshore ROI and onshore NI systems are achieved for all average winter peak days and summer minimum days.

Table 5-6: Pressure Levels for ROI Onshore System - Average Winter Peak Day and Minimum Summer Forecast

	11/ 12	12/ 13	13/ 14	14/ 15	15/ 16	16/ 17	17/ 18	18/ 19	19/ 20	20/ 21
Scenario 1										
Scenario 2										
Scenario 3										
Scenario 4										

Pressures can meet demands **Pressures cannot meet demands**

Table 5-7: Pressure Levels for NI Onshore System - Average Winter Peak Day and Minimum Summer Forecast

	11/ 12	12/ 13	13/ 14	14/ 15	15/ 16	16/ 17	17/ 18	18/ 19	19/ 20	20/ 21
Scenario 1										

Scenario 2										
Scenario 3										
Scenario 4										

Tables 5-8 and 5-9 summarises when pressure levels can and cannot meet demands in both the onshore ROI and onshore NI transmission systems based on the 1-in-50 winter peak day forecasts for each supply scenario. Green indicates when resultant pressures can meet demands whereas yellow indicates that resultant pressure levels cannot meet demands.

Table 5-8: ROI Onshore System 1-in-50 Peak Day Forecasts

	11/ 12	12/ 13	13/ 14	14/ 15	15/ 16	16/ 17	17/ 18	18/ 19	19/ 20	20/ 21
Scenario 1										
Scenario 2										
Scenario 3										
Scenario 4										

Pressures can meet demands **Pressures cannot meet demands**

Low pressures are observed in the southern section of the onshore ROI network (Waterford & Cork) in 2017/18 and 2018/19, where pressure cannot meet demands in 2019/20 and 2020/21. The absence of Inch supplies from 2017/18, results in all of the Cork and Waterford area demand being supplied from Corrib and/or the ICs (Gormanston & Loughshinny). Transporting large volumes of gas through the 18" pipeline between Dublin and Curraleigh West and the 37km 16" pipeline between Goatisland to Curraleigh West, result in substantial pressure losses, which manifest as low system pressures in the Cork and Waterford area. The continuation of Inch supply after 2016/17 would resolve the low pressure levels in the ROI transmission system, identified in Scenario 1.

Table 5-9: NI Onshore System 1-in-50 Peak Day Forecasts

	11/ 12	12/ 13	13/ 14	14/ 15	15/ 16	16/ 17	17/ 18	18/ 19	19/ 20	20/ 21
Scenario 1										
Scenario 2										
Scenario 3										
Scenario 4										

Pressures can meet demands **Pressures cannot meet demands (to power stations)**

As discussed in section 3.5.2, the 1-in-50 winter peak demand for Northern Ireland represents a simultaneous peak day demand across the distribution and power sector including interruptible and firm demand and are conservative. As shown in Table 5-9, this high demand, together with the reduction in the available pressure at the Beattock compressor station and Moffat have provided results where pressures are not capable of meeting demand for a number of years.

Network Analysis also indicates the SNIP does not have sufficient capacity to transport the 1-in-50 peak day demand for NI when pressures approach 56 barg at Twynholm. Rebalancing gas flows between the two NI Entry Points, Twynholm and Gormanston, would resolve the low pressure levels in the NI transmission system, i.e. reducing gas flows through the SNIP and flowing some gas to NI via the ICs and SNP.

5.6.5 *Inch Entry Point*

The results of the network analysis confirm that supplies from the Inch Entry Point are strategically important to the Island.

- As noted in section 5.6.4 the availability of Inch supplies post 2016/17 resolves the low pressure levels in the southern section of the ROI transmission system, identified in scenario 1.
- The availability of Inch supplies amongst other demand and/or supply measures would resolve the potential capacity constraint at the Moffat Entry Point.
- Inch supplies provide an indirect benefit to NI. The availability of Inch supplies reduces the supply requirement at Moffat. Reducing flows through the Moffat Entry Point and SWSOS, results in higher prevailing pressures at Twynholm and consequently higher pressures in the NI transmission system. The low pressure levels identified in scenario 1 for 2017/18 and 2018/19 are resolved in scenario 2, i.e. when Inch supply continues. (See table 5-7)

5.6.6 *Shannon LNG*

The developers of the proposed Shannon LNG terminal have indicated their facility may be developed on a phased basis, with a maximum supply capacity of 11.3 mscmd in phase I increasing to 28.3 mscmd in the final phase, phase III.

This year's JGCS has assumed the supply capacity associated with phase I for all relevant years, i.e. 2017/18 to 2020/21. The network analysis indicates the proposed supply capacity for phase I, 11.3mscmd, can be accommodated for the 1-in-50 winter peak day and average year winter peak day (except for 1 year, 2017/18[17]). Modelling also indicates Corrib and Shannon can meet the Island's balance of supply on a summer minimum day.

As noted in previous JGCS, there is a limitation to the amount of gas that can be physically transported from the west coast to east and/or south coast on 1-in-50 year and average year winter peak days while maintaining pressure within maximum and minimum system pressure limits. The network analysis undertaken for this statement indicate this limit is relatively unchanged, approximately 18 mscmd, based on the combined supplies of Corrib and Shannon and pressures of 55 barg at Dublin City Gates.

Network analysis assumes a very low pressure in the Dublin area, i.e. the minimum pressure requirement of 55 barg at Dublin City Gates, in order to maximise Shannon LNG supplies. However in practice such a low minimum pressure would be regarded as a trigger for system reinforcement. The actual minimum operating system limit at Dublin City Gates is currently of the order of 60 barg. Further studies would be required to determine the optimal network configuration under such supply conditions.

The combined supplies of Corrib and Shannon LNG are consumed by ROI demand on both the 1-in-50 and average winter peak days. However, there is surplus ROI supply available on the summer minimum day, which could be transported to NI. Network analysis indicates the NI summer minimum day demand can be met by the surplus ROI supply via the SNP. This is contingent on technical changes to the Irish network and to the NI network. In this regard it is important to note the impact on the overall Irish network.

5.6.7 *Larne Storage*

As noted in previous statements, the withdrawal and injection rates for the Larne storage project are subject to NI demand, and the capacity of the SNIP and SNP pipelines. In summary;

- Withdrawal = NI Demand + SNP Capacity (north to south flows) + SNIP Capacity (Reverse Flow)
- Injection = SNP Capacity (south to north flows) + SNIP Capacity (Forward Flow) - NI Demand

The Larne withdrawal and injection rates are similar to those published in previous statements. Assuming the necessary system modifications are in place at the relevant control points on the network (i.e. pressure/flow regulation and compression facilities), the proposed maximum Larne storage withdrawal rate, 22 mscmd, can almost be facilitated, in the winter peak day scenarios. Network analysis indicates approximately 21 mscmd of gas can be withdrawn on a winter peak day for both an average year and 1-in-50 year. However, accommodating such flows is subject to low pressures in the SWSOS, ICs and the ROI onshore transmission system, which may not be

[17] Assumed minimum pressure limits at Dublin City Gates are breached. Approximately 11.0 mscmd of gas can be accommodated without breaching the assumed minimum pressure limits.

operationally acceptable. The proposed injection rate, 12 mscmd, can be achieved for the summer minimum day for all years analysed[18].

The results of the network analysis also indicate a wider range in system pressures (albeit within limits) and greater within-day pressure volatility (particularly at the more peripheral points of the network), than current pressure conditions. This change can be attributed to the changing supply position and/or network configuration. In addition to a greater stress on the system, such an increase in the system pressure range would have implications for pressure regulation facilities. Further detailed studies would be required (subject to the advent of Larne) to assess the impact of the increased range and variation in system pressures.

5.6.7.1 SNP (North to South Flows) – Storage Withdrawals

The volume of gas that can be to be transported to the ROI via the SNP is determined by; the pressure available at Larne and the prevailing pressures in the north Dublin area (Gormanston).

The pressure available at Larne is assumed to be up to 85 barg. Modelling indicates pressures vary between 77 barg and 85 barg in line with the demand diurnal profile, i.e. lower pressures during periods of high demand and higher pressures during periods of low demand.

Network analysis assumes a minimum pressure requirement of 55 barg at Dublin City Gates (Abbotstown and Brownsbarn). However, this assumed minimum pressure would be regarded as a trigger for system reinforcement rather than a minimum system operating limit. The minimum operating system limit at Dublin City Gates would be in excess of 60 barg, subject to within day system operational requirements. The pressures at Gormanston recorded in the network modelling ranged from c. 62 barg to 69 barg.

The pressure at Gormanston is determined by the discharge pressure from the ICs. This pressure was set at the lowest possible level in Scenario 3 to maximise SNP (north to south) flows while ensuring minimum pressure requirements were not breached on the ROI system. It should be noted that operating the ROI system close to assumed minimum operating limits impacts on security of supply, i.e. limited onshore line-pack, and may not be operationally acceptable. Further detailed studies would be required, to determine the optimal solution for such a network configuration.

Modelling indicates flows through the SNP, range from c. 3.4 mscmd to 4.4 mscmd, with higher flows possible on average winter peak days, than 1-in-50 peak days.

5.6.7.2 SNP (South to North Flows) – Storage Injections

Both the SNIP and SNP pipelines would be required to transport gas to NI on a summer minimum day to meet the NI demand and the proposed maximum storage injection rate, 12 mscmd. Modelling indicates the SNP would be required to transport approximately 6.8 mscmd of the NI requirement, assuming the gas is entering the SNP at the Gormanston Exit Point from the ICs.

The SNP’s capacity to transport 6.8 mscmd of gas is subject to a pressure of 85 barg at the southern end of the SNP (Gormanston). The ability to provide 85 barg pressure at the southern end of the SNP (Gormanston) is subject to gas being supplied from the ICs (which operate at a high pressure). If gas was being transported from the ROI onshore system, pressures would be less than 70 barg and consequently the capacity of the SNP (for south to north flows) would reduce.

The network analysis undertaken for the JGCS assesses the capacity of the transmission pipelines. The AGIs at the Entry Points to the NI transmission system would need to be assessed to determine if modifications would be required to facilitate the high gas flows, and if so, the scale and cost of such modifications.

5.6.7.3 SNIP – Reverse Flow

The volume of gas that can be transported to ROI via the SNIP, Twynholm and the IC is subject to;

- Twynholm capacity; and
- Operating conditions at Beattock compressor station; and
- Minimum pressure requirement at the inlet of Brighouse Bay compressor station of 52 barg.

Twynholm is designed to flow gas east to west, i.e. from the SWSOS into the SNIP. Modifications would be required at Twynholm to facilitate reverse flows, from west to east, i.e. the SNIP into the SWSOS.

[18] Subject to additional analysis of the AGIs at the Entry Points to the NI transmission system.

The design capacity of Twynholm is 8.64 mscmd; however current capacity is limited by the contractual capacity of 8.08 mscmd at the Twynholm Exit Point on the BGÉ UK system. Modelling indicates that by removing the capacity restrictions at Twynholm and maintaining a minimum of 52 barg at Brighouse Bay, flows may increase up to approximately 9.7 mscmd and 10.4 mscmd on a 1-in-50 winter peak day and an average year winter peak day respectively, subject to a relatively low flow requirement at Moffat[19]. Higher flows through the SWSOS results in higher pressure losses on the system, resulting in lower pressures at Brighouse Bay. Consequently, higher reverse flows through the SNIP and Twynholm can be attained on average winter peak days, when flows from Moffat are lower than flows on 1-in-50 winter peak days.

For JGCS modelling purposes it is assumed Twynholm AGI is bi-directional for reverse flows through the SNIP. The minimum pressure requirement at Brighouse Bay, 52.0 barg, is based on the stations minimum design pressure. It should be emphasised that operating the SWSOS and IC system at lower pressures, in order to facilitate the SNIP reverse flow, results in lower levels of interconnector linepack consequently reducing the security of supply of the system and may not be operationally acceptable. Further detailed studies would be required, to determine the optimal solution for such a configuration.

Twinning the existing pipeline between Cluden and Brighouse Bay may also allow for increased reverse flows through the SNIP and higher withdrawal rates from Larne storage. The twinning of the pipeline could also facilitate a two tier system, which could address the gas quality issues associated with supplying odourised gas to the GB NTS and provide for greater system flexibility in the SWSOS, thus mitigating the risks associated with operating the SWSOS at low pressures.

5.6.8 *Peak-day and Local Reinforcement*

The results and conclusions detailed in the previous sections of this chapter are subject to gas demand growth at a national level. If localised growth was to exceed the national growth levels, there may be a requirement for reinforcement at the relevant location on the local transmission network.

[19] It should be noted, such low flow requirements at Moffat are less than the minimum flow limit of the Moffat Entry Point (Beattock compressor station).

5.7 Supply

The 2012 Joint Gas Capacity Statement (JGCS) presents an assessment of the ability of the all-island transmission network to meet forecast gas demand and potential supply scenarios over the next ten years (2011/12 to 2020/21). In the medium term, the island's demand will continue to be met from GB imports via the Moffat Entry Point and from gas storage at Inch.

5.7.1 *Supply Scenarios*

Four supply scenarios were developed in light of information provided on proposed timings and forecast flows from these current and prospective gas producers/storage operators. The impact of these supply scenarios and of forecast demand on the transmission system over the next ten years was modelled by BGN using specialist network analysis software. The aim of the scenario analysis is to examine whether the system is adequate to cope with a reasonable expectation of demand. It should be taken into account that, while this JGCS has examined potential gas flows from various Entry Points, actual flows will be determined by shipper nominations. These supply scenarios are as follows:

Figure 6.1. Supply Scenarios

Scenario 1	Scenario 2	Scenario 3	Scenario 4
Corrib From 2015/16	Corrib From 2015/16	Corrib From 2015/16	Corrib From 2015/16
Inch Until 2016/17	Inch All Years	Inch All Years	Inch All Years
Moffat	Moffat	Larne 2017/18	Shannon 2017/18
		Moffat	Moffat

5.7.2 *Corrib*

In relation to Corrib gas it is assumed that production will come online during 2015/16. At present work is nearing completion on the construction of the Bellanaboy terminal in County Mayo. Final planning consents have been received and work on the final section of pipeline is ongoing. This pipeline will route through Sruwaddacon Bay. The completion of the Corrib infrastructure and the subsequent exports from April 2015 will significantly impact the security of supply scenario in Ireland. Corrib as is expected to meet 24.4% of the total forecast BGE system 1-in-50 peak-day demand and 44.1% of all island demand in 2015/16. Corrib will on average provide 42% of all island gas demand over the first 2 years of operation.

5.7.3 *Inch*

Inch is considered as being available until 2016/17 in one scenario 1 and is considered as being available on an ongoing basis in all other scenarios. PSE Kinsale Energy Limited has indicated that the economic viability of the existing storage facility is linked to that of its gas production operations. As gas production declines the existing storage operations will not be economically viable on a standalone basis. Therefore existing storage may cease in 2013/14 and decommissioning will take place up to and including 2016/17.

5.7.4 *Larne Storage*

Storage from Larne is considered as a supply source from 2017/18. The Islandmagee Storage project is currently in the development stages. The 5.514 GWh (500mscm) facility under Lough Larne is expected to commence operations in 2017/18. The project received planning permission and was granted a gas storage licence in October 2011.

5.7.5 *Shannon LNG*

Shannon LNG has proposed 2017/27 as the earliest date for its proposed LNG facility at Ballylongford Co. Kerry. Planning permission has been granted for both the terminal and the transmission pipeline that will deliver gas into the ROI transmission system. Shannon LNG proposes to develop the project on a phased basis. Initially it is proposed that the LNG storage tanks and re-gasification facilities will offer a capacity of 127 GWh/d (11.3 mscm/d). Thereafter, two additional expansion phases are proposed with capacities of 191.1 GWh/d (17 mscm/d) and 314.7 GWh/d (28.3 mscm/d) respectively.

5.7.6 *Balance of Supply*

In all scenarios the remainder of gas demand is met from the Moffat Entry Point. The two interconnectors to GB (IC1 and IC2) connect into the BG National Transmission System at the Moffat Entry Point. IC2 was completed in 2002 to meet the expected increase in demand and also supplies gas to the Isle of Man. In 2010/11 Moffat provided 95.1% of total island demand which equated to 72,320 GWh/y (6,549 mscm/y).

It is important to note that the Regulatory Authorities have not sought to take a view on the commercial viability of existing or proposed projects. The inclusion of data and in particular the timelines for these projects in the JGCS modelling is based on information provided by project promoters. It is not intended to refer to the likelihood of these infrastructure projects being progressed to commercial viability.

5.8 Demand

ROI annual gas demand contracted by 4.6% in 2010/11 compared to 2009/10. A number of factors influenced this demand decrease. Power sector generation demand sharply on the previous year (considered mainly due to less severe weather and increased renewables). The residential sector continued to contract due to the ongoing economic uncertainty. While some of the growth seen in the I/C sector was due to a reclassification of CHP, from power into this category. Additionally, the performance of export oriented companies is considered to have had a positive impact on demand for this sector.

Total annual gas demand in Northern Ireland has increased by 2.98% from 2009/10 to 2010/11. This increase was caused largely by the unavailability of the Moyle interconnector which resulted in lower imports and therefore increased use of gas fired power stations in Northern Ireland.

However in more recent years total annual gas demand has fallen. This overall decrease in demand from 2006/2007 until 2009/10 has occurred as a result of the economic recession, power generation dispatch moving from Northern Ireland to the Republic of Ireland and an increase in renewable energy sources.

The distribution sector within Northern Ireland continues to grow with an increase of 5.81% in annual demand from 2009/10 to 2010/11. This represents steady growth within the Phoenix Natural Gas and Firmus distribution systems.

5.8.1 *ROI Demand by Sector*

5.8.2 *Power Sector*

As noted above power sector demand in ROI fell significantly by 9.9% on the previous year. Power sector demand accounts for 60.8% of total gas demand and therefore a demand decrease in this sector has a noticeable effect on overall gas demand. A changing power generation portfolio has increased the level of efficient CCGT and OCGT plants on the system which includes Aghada CCGT and Whitegate CCGT. A 459MW plant at Great Island Co. Wexford is due to commence commercial operations in 2014.

The JGCS forecast assumes that 753MW of new gas fired CCGT and OCGT will be commissioned during the report period. The retirement of 1,395MW of older, mainly HFO fired plants will occur. As noted above the power sector has seen a significant portfolio change over the last number of years. In particular, the ongoing connection of renewables has resulted in the necessity to ensure that fast acting gas fired generation is readily available to ensure continuity and security of supplies. Annual power sector gas demand is expected to rise from 31.1TWh/y in 2011/12 to 41.4TWh/y by 2020/21. It should be noted that the actual increase in power sector demand is dependent on a number of factors. These include the level of renewable connections that are expected in the reporting period. Additional factors to be considered include the economic growth rate leading to a recovery in electricity demand, the level of new gas plant efficiencies leading to a higher merit order ranking, an increase in carbon prices and the level of imports from BETTA across the electricity interconnectors.

5.8.3 *I/C & Residential Sectors*

In contrast with power sector demand, I/C gas demand grew by 13.9% in 2010/11. This increase was due in large part to the reclassification of I/C sector demand to include CHP. The strong growth was particularly significant in the transmission connected I/C sector which is attributable to strong economic performance of export oriented sectors of the economy including agribusiness.

In modelling future I/C demand growth it is assumed that demand growth will correspond to 80% of economic growth forecasts. Thus a steady pace of growth is expected until 2017/18. From then a higher growth rate is expected. However, it should be noted that efficiencies in line with the National Energy Efficiency Action Plan (NEEAP) are expected to dampen demand slightly.

Residential gas demand growth has remained low with a customer growth rate of 0.9% in 2010/11. This growth was lower than had been expected due to higher vacancy rates, higher gas prices and smaller dwelling sizes. For 2011/12 there is a low level of expected new builds of 1,200. Future forecast growth is expected to reflect a similar pattern to I.C demand i.e. dependent on economic growth rates and energy efficiencies.

5.8.4 *Summary*

Overall, total ROI annual gas demand is forecast to grow at an average rate of 2.9% p.a. over the reporting period up to and including 2020/21. These figures are slightly ahead of the 2011 JGCS estimates. This is primarily due to an increase in demand from I/C and residential customers in line with economic growth.

5.8.5 *NI Demand by Sector*

5.8.6 *Power Sector*

Power sector demand in Northern Ireland has increased by 1.85% in 2010/11 compared to 2009/10. The increase in power sector demand was caused by the unavailability of the Moyle interconnector which resulted in lower imports and therefore increased use of gas fired power stations in Northern Ireland.

Future demand is expected to remain relatively stable however this is dependent upon a number of variable factors.

5.8.7 *Distribution Sector*

Demand in the Northern Ireland distribution market is forecast to grow at an annual rate of 2.8% p.a. over the period modelled, depicted in Figure 3-18. The year-on-year increase reflects the distribution companies' expected growth rates within the domestic and I/C sectors. Forecast growth rates have also been revised to take into account prevailing economic conditions as well as the effect of energy efficiency measures across the sector.

5.8.8 *Summary*

Overall demand is forecast to grow at an average of 1.62% per annum over the reporting period up to and including 2020/21.

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6 Modelling Results

6.1 Moffat Entry Point –NTS Pressures

As noted in Chapter 5 of this report, one of the primary determinants of the capacity at the Moffat Entry Point is the pressures available from the National Grid NTS at Moffat. The current technical capacity of 31 mscmd is based on an ANOP pressure of 47 barg. However, actual pressures approaching 45 barg have been observed on various occasions over the past 24 months. National Grid is contractually required to provide gas at a minimum pressure of 42.5 barg (for flows up to 26 mscmd), under the existing Pressure Maintenance Agreement (PMA). Lower pressures at Moffat imply a lower technical capacity for the Moffat Entry Point.

Gaslink and BGN have engaged with National Gird regarding Moffat NTS pressures, and have been advised that the occurrence of pressures below the 47 barg are isolated 'within day' incidents, and that it is prudent to continue assuming the ANOP pressure of 47 barg for the current year and following 3 years, for Network Planning purposes.

National Grid has indicated that the Moffat Exit Point is classified as a null point[20] from a network analysis point of view on the GB NTS, due to the change in GB flow patterns. GB gas supplies from the north (St. Fergus) have substantially reduced over the last 10 years, due to the decline in UK Continental Shelf (CS) production and increased from the south, due to the commissioning of the LNG terminals at Milford Haven and the Isle of Grain combined with additional Norwegian Imports at Easington.

In response to the consultation with National Grid, BGN will be assuming the ANOP Moffat NTS pressure of 47 barg until 2014/15 (inclusive) and a lower pressure of 45 barg from 2015/16. This assumption will be reviewed on an ongoing basis.

Network Analysis has determined the technical capacity of the Moffat Entry Point is 29 mscmd, based on an inlet pressure of 45 barg at the Moffat Exit Point on the GB NTS. Consequently, the capacity of the Moffat Entry point is assumed to reduce from 31 mscmd to 29 mscmd for all years from 2015/16 (inclusive).

As noted in Section 5.6.3.1 assuming that Inch storage ceases in 2013/14 then constraint at Moffat is very likely to occur. Where constraints are likely, new sources of supply may resolve the potential constraint capacity. These potential new sources include Corrib Shannon LNG and Larne Storage projects. The development of new supply sources on the island will help to reduce the peak day flow requirements at the Moffat Entry Point, and reduce potential capacity constraints. Where new supply sources do not materialise then demand and/or supply side measures may be required.

6.2 Potential Reduced Pressures Levels in ROI

Low pressures are observed in the southern section of the onshore ROI network (Waterford & Cork) in 2017/18 and 2018/19, with the assumed minimum pressure limits being breached in 2019/20 and 2020/21. The absence of Inch supplies from 2017/18, results in all of the Cork and Waterford area demand being supplied from Corrib and/or the ICs (Gormanston & Loughshinny). Transporting large volumes of gas through the 18" pipeline between Dublin and Curraleigh West and the 37km 16" pipeline between Goatisland to Curraleigh West result in substantial pressure losses, which manifest as low system pressures in the Cork and Waterford area. The continuation of Inch supply after 2016/17 would resolve the low pressure levels in the ROI transmission system, identified in Scenario 1.

[20] A null point is a term used by network analysts to describe an offtake point on a feeder where typically all flows will be towards that point and there are no flows past the point. In the case of Moffat this means that the offtake is typically fed simultaneously from both the north and the south and hence there is no NTS flow past the point from North to South (or South to North).

6.3 Potential Reduced Pressure Levels in NI

Modelling has shown low pressure levels in the NI onshore system in all four scenarios for the 1-in-50 winter peak demand between 2011/12 and 2014/15. The low pressure levels mean that the transmission network cannot meet powerstation demand when Twynholm is the only Entry Point being utilised. Low pressure levels which cannot meet winter peak demand are also seen in later years where new supply sources do not enter production.

Re-routing some of NI gas requirement from Moffat through the ICs and the Gormanston (NI) Entry Point would resolve the minimum pressure issues in the NI onshore system.

Additionally network analysis indicates the SNIP does not have sufficient capacity to transport the forecast 1-in-50 peak day demand for NI when pressures approach 56 barg at Twynholm. Rebalancing gas flows between the two NI Entry Points, Twynholm and Gormanston, would resolve the potential low pressure levels in the NI transmission system, i.e. reducing gas flows through the SNIP and flowing some gas to NI via the ICs and SNP.

If Gormanston is not used, the current 'flip-flop' arrangements contained in PTL's network code would also allow the powerstations to continue to generate electricity. Under 'flip-flop' arrangements Ballylumford and Coolkeeragh powerstations take it in turn to reduce gas nominations and switch to secondary fuels until pressures in the gas transmission system are restored.

The availability of Larne Storage from 2017/18 would resolve the minimum pressure issues in later years.

The results for the 1-in-50 peak day demands are due to a change in pressure assumptions at the Moffat Entry Point and Beattock Compressor station in Scotland together with a high forecast peak day demand.

As noted in section 3.5.2, the Utility Regulator has reviewed the 1-in-50 winter peak day forecast and concluded that the likelihood of such a high winter peak demand is low

Network modelling also indicates that system pressures in both the onshore ROI and onshore NI systems are within system pressure limits for all average winter peak days and summer minimum days. Again, as noted previously the data provided for the average winter peak day is closer to the winter peak demands that were recorded in the severe winter periods of 2009/10 and 2010/11 which demonstrates the capability of the transmission network to handle such high demands.

For the years indicated, the reduction in available pressure levels on the NI onshore system presents a potential issue for powerstations since the transmission system does not have the required pressure to meet the 1-in-50 demands. As above, the likelihood of such a high winter peak demand is low; however power stations have the right to request enhanced pressure under the relevant network codes in Northern Ireland.

6.4 Updates to 2011 JGCS

Since the publication of the 2011 JGCS a number of changes have occurred to mitigate possible capacity issues on the gas network. Virtual Reverse Flow products were introduced at Moffat at the end of 2011. This is of particular interest to users of the Inch storage products. Ongoing dialogue between electricity and gas TSOs is resulting in a more co-ordinated approach to system operation in recognition of the increasing interdependency of gas and electricity markets. In addition, bi-lateral discussions have taken place between Gaslink and the major power station users to encourage more timely information regarding gas flow requirements. It is hoped that this will result in more effective scheduling and ease concerns of enforcement of strict re-nomination rules. .

Finally, the recently published Price Control 3 (PC3) has allocated €1 million to the longer term review of the requirements for the onshore Scotland system. The allocation as part of PC3 aims to provide a 10 year horizon view of the requirements for onshore Scotland, compressors and pipelines.

6.5 Regulation 994/2010

It should be noted that as per EU Regulation 994/2010 a full assessment of the risks affecting security of supply is to be carried out by the Competent Authority in each Member State. The CER, as the Competent Authority completed this work and published its Preventive Action Plan on 4th December 2012. The Preventive Action Plan is reviewed biennially. The Plan is partially based on the supply scenarios that are outlined in gas capacity statements. The Preventive Action Plan focuses primarily on risk management which aims to ensure that supplies are safeguarded for protected customers. An Emergency Plan is also detailed.

The Department of Energy and Climate Change (DECC) is the Competent Authority for the UK and published its Preventative Action Plan and Emergency Plan in November 2012.

6.6 Longer Term Issues

GB imports through Moffat will remain an integral aspect of the island's transmission systems. The 2011 Report stated that capacity limits will be approached in 2013/14 where existing Inch Storage ceases and peak demand forecasts arise. This issue remains but is not foreseen before 2014/15. Despite the changing portfolio towards more sources on the island the importance of Moffat to supplies will continue for the reporting period.

The introduction of new indigenous supply sources including Corrib, Shannon LNG and Larne Storage will mitigate the capacity constraints that Moffat will face during the latter years where those scenarios arise.

Overall, the commercial and operational arrangements of the all-island gas market will continue to be heavily influenced by developments in GB.

7 Conclusion and Recommendations of the Regulatory Authorities

- In the medium term, the island's demand will continue to be met from GB imports via the Moffat Entry Point and from gas production and storage at Inch. The timing and availability of indigenous gas projects are critical to ensure that capacity limits at the Moffat Entry Point are not beached.

- The network modelling carried out by BGN indicates that capacity limits at the Beattock Compressor Station in onshore Scotland may potentially be breached in 2015/16 if flows from Inch begin to decline between 2013/14 and 2016. A number of products have been introduced since the 2011 JGCS which may serve to facilitate the continuing operation of the existing storage facility at Inch.

- Modelling has shown low pressure levels in the NI onshore system in all four scenarios which cannot meet the 1-in-50 winter peak demand to power stations between 2011/12 and 2014/15. Low pressure levels which cannot meet winter peak demand are also seen in later years where new supply sources do not enter production.

    - As stated in section 3 the 1-in-50 winter peak forecasts include both firm and interruptible demand and also represent a simultaneous peak occurring across both the distribution and power generation sectors. The Utility Regulator has reviewed the 1-in-50 winter peak day forecast and concluded that the likelihood of such a high winter peak demand is low.

    - Modelling has shown the ability of the NI transmission system to meet average winter peak demand in all scenarios and for all years modelled as set out in section 5.

    - The figures provided for the average winter peak day are closer to the winter peak demands that were recorded in the severe winter periods of 2009/10 and 2010/11 which demonstrates the capability of the transmission network to handle such high demands.

    - For future capacity statements it may be more beneficial to consider how the data on the peak day is presented to ensure it is more beneficial to industry.

    - There are arrangements in place should pressure levels within the NI transmission system not be able to provide the 1-in-50 winter peak demand modelled. These include flip-flop arrangements and use of the SN pipeline. Power stations also have the right to request enhanced pressure under the relevant network codes in Northern Ireland.

- In the longer term, new sources of supply described in the JGCS may significantly change the direction and nature of flows on the island's transmission network. It is evident that where a number of supply projects enter the system network analysis will be required to ensure that low operating pressures are not encountered on the system.

In summary the requirement for future investment is highly dependent on;

1. The timing of new indigenous projects;
2. The increase in demand due to economic recovery, energy efficiencies, severe weather events and the merit order of gas fired generation within the SEM;
3. The success of products that mitigate constraints and facilitate gas market liquidity.

The Regulatory Authorities welcome the continued co-operation within the framework of the CAG project and would like to thank all parties involved in the preparation of the JGCS 2012.

Appendix 1: Peak Day Demand Forecasts

ROI Peak-day demand forecast

The ROI peak-day demands are summarised in Tables A1-1 to A1-4. These represent the forecasted peak-day demand under severe 1 in 50 weather conditions, i.e. weather conditions so severe that statistically they are only likely to occur once every fifty years.

In line with previous statements the distribution peak-day demand is weather corrected to 1 in 50 weather conditions. The power sector peak day demands however are calculated by applying the Generation Capacity Statement (GCS) median growth rate profile to the actual winter 2010 peak electricity demand which was 5,090MW. The transmission connected I/C sites are not weather corrected, as their daily demand tends to be driven by relative fuel-prices and economic growth etc (and in aggregate are not weather sensitive). The process for deriving the peak-day demands may be summarised as follows:

- The daily demand from each power station is generated directly from a merit-order stack model of the electricity market. The peak demand growth is forecast in line with EirGrid's prediction of annual peak demand growth as issued in the AGCS with the initial demand for 2010/11 taken as the actual electricity peak demand of 5,090MW which occurred on 21st December 2010;

- The daily demand of the transmission connected Daily Metered (DM) I/C sites is derived from their forecast annual demand, using the historical daily profile for the sector;

- The daily demand of the distribution connected DM I/C sites is derived from their forecast annual demand (weather corrected), using a profile derived from a regression model (which is used to derive the relationship between the daily demand of the sector and the weather, and takes account of 1 in 50 weather conditions); *and*

- The daily demand of the Non-Daily Metered (NDM) sector is similarly derived from their forecast annual demand (weather corrected), using a profile derived from a regression model (which takes account of 1 in 50 weather conditions).

The daily gas demand from each of the above sectors is then combined into its power, I/C and residential components. This involves splitting the NDM peak-day demand into its residential and I/C components. The ROI peak-day demand is assumed to be equal to the aggregate peak-day demand of the power, I/C residential sectors. The daily demand for the ROI power sector is based on the likely usage of ROI power stations taking into account forward fuel prices, etc. Assumptions include the peak day availability of non gas fired stations. The peak day power sector forecast demand is less than the sum of the maximum potential demand (as it is considered unlikely that all gas fired stations would operate at maximum potential load on a peak day).

NI Peak-day demand

The NI peak-day demand was derived from information provided by the NI gas distribution companies and powerstations. The peak-day forecast is summarised by sector in Table A1-5.

IOM Peak-day forecast

The peak-day demand forecast for the IOM was based on information provided by the Manx Electricity Authority (MEA), who also operate the natural gas system on the IOM. In the tables that follow, volume conversion calculations have been carried out using a weighted average of forecast peak day supplies for the particular supply scenario and take into account the relevant calorific value of the gas delivered at each Entry Point.

Table A1-1: 1 in 50 Winter Peak day Demand & Supply Scenario 1

	11/ 12	12/ 13	13/ 14	14/ 15	15/ 16	16/ 17	17/ 18	18/ 19	19/ 20	20/21
ENERGY	GWh/d									
Power	147.8	133.8	141.3	143.2	158.0	161.3	164.4	166.9	170.0	173.7
I/C	54.6	55.7	56.9	58.2	59.1	60.0	61.1	62.2	63.3	64.0
Res	69.9	69.5	69.0	68.5	68.1	67.6	67.2	66.7	66.3	65.9
Own-use	5.3	5.1	5.2	5.5	4.5	4.7	5.1	5.1	5.2	5.2
Total ROI	277.5	264.0	272.4	275.4	289.6	293.7	297.7	300.9	304.8	308.8
IOM	5.3	5.7	5.7	5.7	5.8	5.8	5.8	5.8	5.9	5.9
NI	88.5	89.2	87.9	87.1	85.6	86.6	87.6	88.7	89.7	91.0
Total CAG	371.3	358.9	365.9	368.2	381.0	386.1	391.2	395.4	400.3	405.7
Inch	34.2	33.7	33.1	17.4	9.8	5.3	0.0	0.0	0.0	0.0
Corrib	0.0	0.0	0.0	0.0	92.9	84.7	72.4	72.7	70.0	61.8
Larne	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Shannon	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Moffat	337.1	325.2	332.9	350.8	278.3	296.1	318.8	322.7	330.3	343.9
Total	371.3	358.9	365.9	368.2	381.0	386.1	391.2	395.4	400.3	405.7
VOLUME	mscm/d									
Power	13.4	12.2	12.8	13.0	14.5	14.8	15.1	15.3	15.6	15.9
I/C	5.0	5.1	5.2	5.3	5.4	5.5	5.6	5.7	5.8	5.8
Res	6.3	6.3	6.3	6.2	6.3	6.2	6.1	6.1	6.1	6.0
Own-use	0.5	0.5	0.5	0.5	0.4	0.4	0.5	0.5	0.5	0.5
Total ROI	25.2	24.0	24.7	25.0	26.6	27.0	27.3	27.5	27.9	28.2
IOM	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
NI	8.0	8.1	8.0	7.9	7.9	8.0	8.0	8.1	8.2	8.3
Total CAG	33.7	32.6	33.2	33.4	35.1	35.4	35.8	36.2	36.6	37.1
Inch	3.2	3.2	3.1	1.7	0.9	0.5	0.0	0.0	0.0	0.0
Corrib	0.0	0.0	0.0	0.0	8.9	8.1	7.0	7.0	6.7	5.9
Larne	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Shannon	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Moffat	30.5	29.4	30.1	31.8	25.2	26.8	28.9	29.2	29.9	31.1
Total	33.7	32.6	33.2	33.4	35.1	35.4	35.8	36.2	36.6	37.1

Table A1-2: 1 in 50 Winter Peak day Demand & Supply Scenario 2

	11/ 12	12/ 13	13/ 14	14/ 15	15/ 16	16/ 17	17/ 18	18/ 19	19/ 20	20/21
ENERGY	GWh/d									
Power	147.8	133.8	141.3	143.2	158.0	161.3	164.4	166.9	170.0	173.7
I/C	54.6	55.7	56.9	58.2	59.1	60.0	61.1	62.2	63.3	64.0
Res	69.9	69.5	69.0	68.5	68.1	67.6	67.2	66.7	66.3	65.9
Own-use	5.3	5.1	5.2	5.3	4.2	4.4	4.6	4.7	4.8	5.0
Total ROI	277.5	264.0	272.4	275.2	289.3	293.3	297.3	300.4	304.4	308.5
IOM	5.3	5.7	5.7	5.7	5.8	5.8	5.8	5.8	5.9	5.9
NI	88.5	89.2	87.9	87.1	85.6	86.6	87.6	88.7	89.7	91.0
Total CAG	371.3	358.9	365.9	368.0	380.7	385.7	390.7	394.9	399.9	405.5
Inch	34.2	33.7	33.1	31.6	30.9	30.4	30.0	29.5	29.2	28.8
Corrib	0.0	0.0	0.0	0.0	92.9	84.7	72.4	72.7	70.0	61.8
Larne	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Shannon	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Moffat	337.1	325.2	332.9	336.4	256.8	270.6	288.4	292.7	300.7	314.9
Total	371.3	358.9	365.9	368.0	380.7	385.7	390.7	394.9	399.9	405.5
VOLUME	mscm/d									
Power	13.4	12.2	12.8	13.0	14.6	14.9	15.1	15.3	15.6	15.9
I/C	5.0	5.1	5.2	5.3	5.5	5.5	5.6	5.7	5.8	5.9
Res	6.3	6.3	6.3	6.2	6.3	6.2	6.2	6.1	6.1	6.0
Own-use	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.5
Total ROI	25.2	24.0	24.7	25.0	26.7	27.0	27.3	27.6	28.0	28.3
IOM	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
NI	8.0	8.1	8.0	7.9	7.9	8.0	8.1	8.2	8.2	8.4
Total CAG	33.7	32.6	33.2	33.5	35.1	35.6	35.9	36.3	36.7	37.2
Inch	3.2	3.2	3.1	3.0	3.0	2.9	2.9	2.8	2.8	2.8
Corrib	0.0	0.0	0.0	0.0	8.9	8.1	7.0	7.0	6.7	5.9
Larne	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Shannon	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Moffat	30.5	29.4	30.1	30.5	23.2	24.5	26.1	26.5	27.2	28.5
Total	33.7	32.6	33.2	33.5	35.1	35.6	35.9	36.3	36.7	37.2

Table A1-3: 1 in 50 Winter Peak day Demand & Supply Scenario 3

	11/ 12	12/ 13	13/ 14	14/ 15	15/ 16	16/ 17	17/ 18	18/ 19	19/ 20	20/21
ENERGY	GWh/d									
Power	147.8	133.8	141.3	143.2	158.0	161.3	164.4	166.9	170.0	173.7
I/C	54.6	55.7	56.9	58.2	59.1	60.0	61.1	62.2	63.3	64.0
Res	69.9	69.5	69.0	68.5	68.1	67.6	67.2	66.7	66.3	65.9
Own-use	5.3	5.1	5.2	5.3	4.2	4.4	4.9	4.4	4.1	4.3
Total ROI	277.5	264.0	272.4	275.2	289.3	293.3	297.6	300.1	303.7	307.9
IOM	5.3	5.7	5.7	5.7	5.8	5.8	5.8	5.8	5.9	5.9
NI	88.5	89.2	87.9	87.1	85.6	86.6	87.6	88.7	89.7	91.0
Total CAG	371.3	358.9	365.9	368.0	380.7	385.7	391.1	394.6	399.2	404.8
Inch	34.2	33.7	33.1	31.6	30.9	30.4	30.0	29.5	29.2	28.8
Corrib	0.0	0.0	0.0	0.0	92.9	84.7	72.4	72.7	70.0	61.8
Larne	0.0	0.0	0.0	0.0	0.0	0.0	66.2	110.5	237.2	234.0
Shannon	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Moffat	337.1	325.2	332.9	336.4	256.8	270.6	222.5	181.9	62.8	80.2
Total	371.3	358.9	365.9	368.0	380.7	385.7	391.1	394.6	399.2	404.8
VOLUME	mscm/d									
Power	13.4	12.2	12.8	13.0	14.6	14.9	15.1	15.3	15.6	15.9
I/C	5.0	5.1	5.2	5.3	5.5	5.5	5.6	5.7	5.8	5.9
Res	6.3	6.3	6.3	6.2	6.3	6.2	6.2	6.1	6.1	6.0
Own-use	0.5	0.5	0.5	0.5	0.4	0.4	0.5	0.4	0.4	0.4
Total ROI	25.2	24.0	24.7	25.0	26.7	27.0	27.4	27.6	27.9	28.3
IOM	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
NI	8.0	8.1	8.0	7.9	7.9	8.0	8.1	8.2	8.2	8.4
Total CAG	33.7	32.6	33.2	33.5	35.1	35.6	36.0	36.3	36.7	37.1
Inch	3.2	3.2	3.1	3.0	3.0	2.9	2.9	2.8	2.8	2.8
Corrib	0.0	0.0	0.0	0.0	8.9	8.1	7.0	7.0	6.7	5.9
Larne	0.0	0.0	0.0	0.0	0.0	0.0	6.0	10.0	21.5	21.2
Shannon	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Moffat	30.5	29.4	30.1	30.5	23.2	24.5	20.1	16.5	5.7	7.2
Total	33.7	32.6	33.2	33.5	35.1	35.6	36.0	36.3	36.7	37.1

Table A1-4: 1 in 50 Winter Peak day Demand & Supply Scenario 4

	11/ 12	12/ 13	13/ 14	14/ 15	15/ 16	16/ 17	17/ 18	18/ 19	19/ 20	20/21
ENERGY	GWh/d									
Power	147.8	133.8	141.3	143.2	158.0	161.3	164.4	166.9	170.0	173.7
I/C	54.6	55.7	56.9	58.2	59.1	60.0	61.1	62.2	63.3	64.0
Res	69.9	69.5	69.0	68.5	68.1	67.6	67.2	66.7	66.3	65.9
Own-use	5.3	5.1	5.2	5.3	4.2	4.4	2.9	2.9	3.0	3.1
Total ROI	277.5	264.0	272.4	275.2	289.3	293.3	295.5	298.7	302.6	306.7
IOM	5.3	5.7	5.7	5.7	5.8	5.8	5.8	5.8	5.9	5.9
NI	88.5	89.2	87.9	87.1	85.6	86.6	87.6	88.7	89.7	91.0
Total CAG	371.3	358.9	365.9	368.0	380.7	385.7	389.0	393.2	398.1	403.6
Inch	34.2	33.7	33.1	31.6	30.9	30.4	30.0	29.5	29.2	28.8
Corrib	0.0	0.0	0.0	0.0	92.9	84.7	72.4	72.7	70.0	61.8
Larne	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Shannon	0.0	0.0	0.0	0.0	0.0	0.0	127.0	127.0	127.0	127.0
Moffat	337.1	325.2	332.9	336.4	256.8	270.6	159.6	164.0	171.9	186.0
Total	371.3	358.9	365.9	368.0	380.7	385.7	389.0	393.2	398.1	403.6
VOLUME	mscm/d									
Power	13.4	12.2	12.8	13.0	14.6	14.9	15.0	15.3	15.5	15.9
I/C	5.0	5.1	5.2	5.3	5.5	5.5	5.6	5.7	5.8	5.8
Res	6.3	6.3	6.3	6.2	6.3	6.2	6.1	6.1	6.1	6.0
Own-use	0.5	0.5	0.5	0.5	0.4	0.4	0.3	0.3	0.3	0.3
Total ROI	25.2	24.0	24.7	25.0	26.7	27.0	27.0	27.3	27.7	28.0
IOM	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
NI	8.0	8.1	8.0	7.9	7.9	8.0	8.0	8.1	8.2	8.3
Total CAG	33.7	32.6	33.2	33.5	35.1	35.6	35.6	36.0	36.4	36.8
Inch	3.2	3.2	3.1	3.0	3.0	2.9	2.9	2.8	2.8	2.8
Corrib	0.0	0.0	0.0	0.0	8.9	8.1	7.0	7.0	6.7	5.9
Larne	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Shannon	0.0	0.0	0.0	0.0	0.0	0.0	11.3	11.3	11.3	11.3
Moffat	30.5	29.4	30.1	30.5	23.2	24.5	14.4	14.8	15.6	16.8
Total	33.7	32.6	33.2	33.5	35.1	35.6	35.6	35.9	36.4	36.8

Table A1-5: 1 in 50 Severe Winter Peak Day Demand for NI

	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21
ENERGY	GWh/d									
Power	55.5	55.5	52.8	50.8	48.1	48.1	48.1	48.1	48.1	48.1
Distribution	33.1	33.7	35.1	36.4	37.5	38.6	39.6	40.6	41.6	42.9
Total NI	88.6	89.2	87.9	87.2	85.6	86.7	87.7	88.7	89.7	91.0
VOLUME	mscm/d									
Power	5.0	5.0	4.8	4.6	4.4	4.4	4.4	4.4	4.4	4.4
Distribution	3.0	3.1	3.2	3.3	3.4	3.5	3.6	3.7	3.8	3.9
Total NI	8.0	8.1	8.0	7.9	7.8	7.9	8.0	8.1	8.2	8.3

Appendix 2: System Modelling Approach

A hydraulic model of the combined Irish and NI transmissions is constructed using Pipeline Studio® software. Pipeline Studio® pipeline simulator allows the user to configure and analyse scenarios using transient modelling.

All scenarios simulate the 24 hour demand cycle of the all-island transmission system over a three day period to obtain steady consistent results.

The "all-island" hydraulic model includes all the major components of the Irish and NI transmission systems, including the Irish 70 barg system, the Dublin City 40 barg systems, the S/N, North/West and SNIP Pipelines. The Irish 19 barg transmission systems are modelled separately.

The transmission network model includes:

- All of the relevant physical characteristics of the transmission Pipelines, including pipeline lengths, wall-thickness and internal diameter;
- All of the major flow-regulating stations, i.e. Twynholm, Carrickfergus, Gormanston (IC2 landfall), Loughshinny (IC1 landfall), Craughwell, and the Dublin City Gates – i.e. Abbotstown, Brownsbarn and Diswellstown:
    - Twynholm is modelled as a flow-control regulating station, with a minimum pressure drop across the regulators of 2.5 barg;
    - Carrickfergus is modelled with a differential-pressure control of 0.5 barg across the regulators;
    - Gormanston discharge from IC2 is be pressure-controlled (with 75% of the IC system flow assumed to come through IC2);
    - The Loughshinny discharge from IC1 is flow-controlled (with 25% of the IC system flow assumed to come through IC1); *and*
    - The discharge from the Dublin City Gates into their respective 40 barg systems is set to be pressure controlled.
- Beattock's discharge pressure is determined by desktop analysis based on the compressor performance characteristics, inlet pressure and temperature conditions and forecasted Moffat flows, for parallel mode of operation (and such that pressures do not exceed 85 barg)
- A generic-compressor model for at Brighouse Bay and Midleton:
    - The Brighouse Bay compressor station is modelled to achieve a flat flow profile; *and*
    - The Midleton compressor station is modelled to achieve a flat flow at the Inch Entry Point.

The hourly peak-day and minimum-day demands for each AGI off-take are entered into the hydraulic model on an energy basis. These are derived from the national peak-day and minimum-day forecasts using the following process:

- The hourly gas demand of the Irish power stations is generated directly by the merit-order stack model;
- The hourly gas demand of the NI power stations was provided by PTL and the Utility Regulator using information received from the shippers to the power stations; *and*
- The hourly demand for all other AGI off-takes was derived from their historic contribution (and pattern) to peak-day and minimum-day demand.

The conditions for the Entry Points are also entered into the hydraulic model, i.e. the supply pressure, the maximum daily flow, the hourly profile and molar composition of the gas. The hydraulic model then solves for the resultant system pressures and flows (taking into account the calorific value of the gas delivered to each Entry Point).

The resultant system pressure, flows and gas velocities are then checked to ensure that they comply with the criteria specified in Section 5. A failure to comply with the specified criteria indicates the need for future reinforcement.

Appendix 3: CAG System Configuration

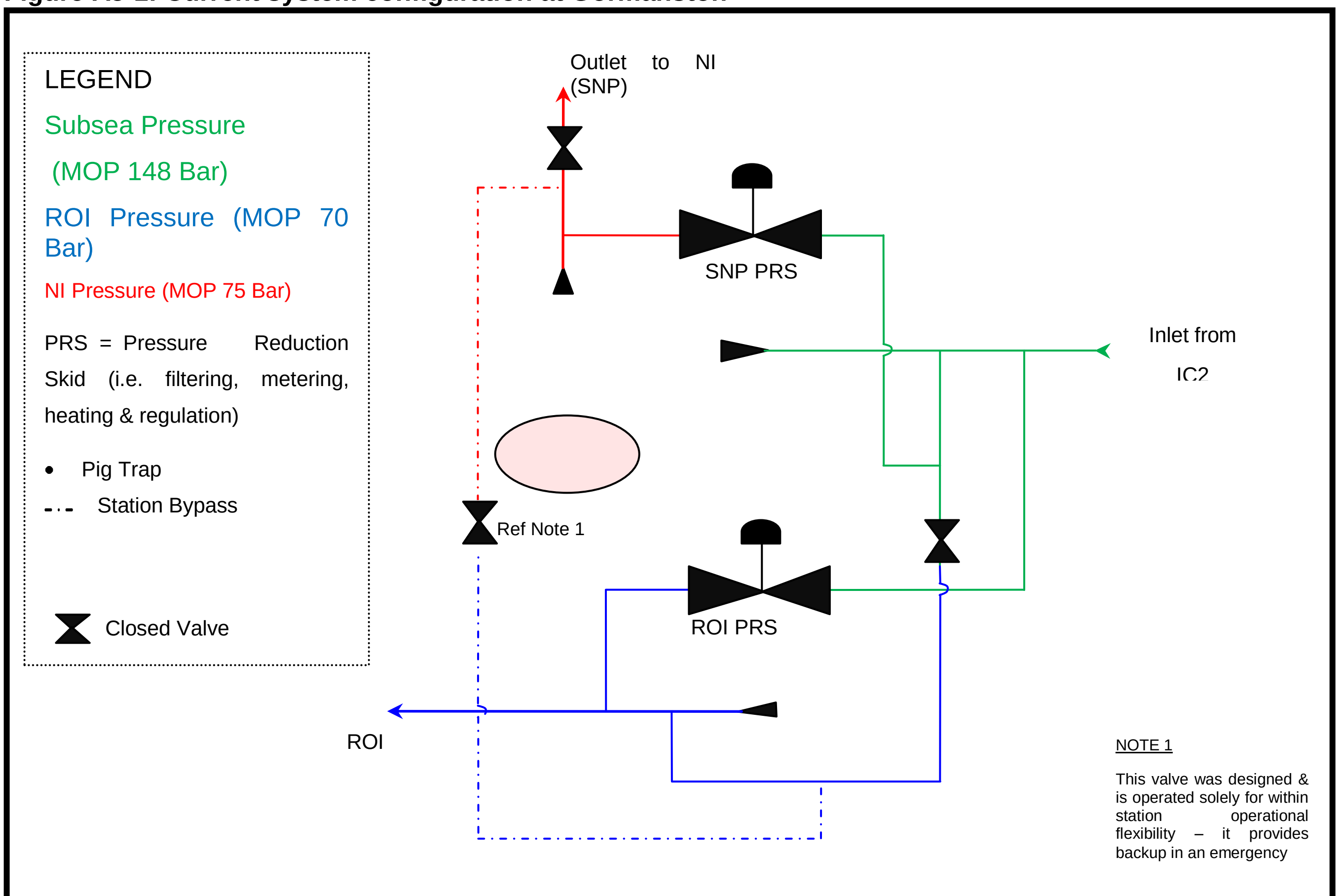
Phase 1 of the IC2 landfall station at Gormanston was constructed in 2002 and provides pressure regulation facilities from the IC2 sub-sea pipeline to the ROI transmission network. Subsequently, Phase 2 of Gormanston AGI was constructed in 2006 as part of the South-North Pipeline (SNP) project which can provide pressure regulation facilities to the NI network.

The current configuration at Gormanston is shown in Figure A5-1:

- The closed block valve highlighted provides for the separation of the two systems;
- The flow of gas from IC2 into the ROI and NI transmission systems is controlled through separate regulators (i.e. the ROI and SNP regulators), with their own individual settings.

The combined effect of this configuration is that the two systems are separated, and have separate pressure control regimes. Under the existing arrangement gas would only flow from IC2 into the SNP in the event of an emergency or if there was insufficient capacity available on the SNIP to meet NI demands.

Figure A5-1: Current system configuration at Gormanston



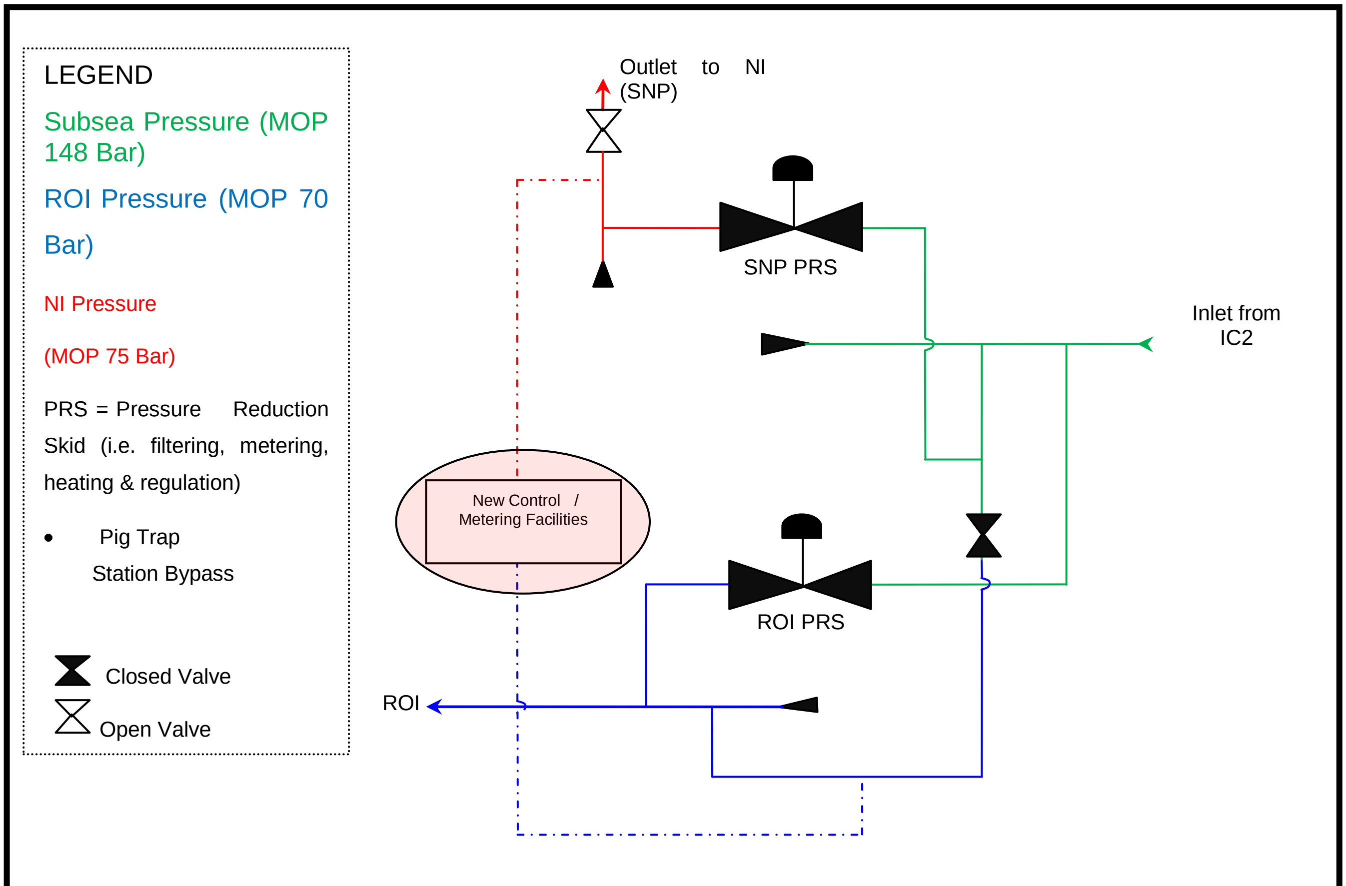
Current Configuration at Gormanston

Under a future CAG operational environment, this existing configuration may change to a 'CAG' configuration, where given certain supply and demand scenarios there may be excess gas supplies in either jurisdiction, available for supply to the other jurisdiction.

With the existing system configuration there is no control mechanism or metering available to control the flow of gas between the ROI and NI. The gas would simply flow between the two systems depending on the relative system pressures on the ROI and NI transmission systems, subject to MOP limits.

In order to facilitate the 'CAG' configuration, significant system modifications would be required, particularly at Gormanston AGI, to include metering, flow control and pressure control (See figure A5-2). Modifications may also be required at Twynholm, Carrickfergus and Ballyalbanagh.

Figure A5-2: Requirements at Gormanston to accommodate CAG configuration



CAG Configuration at Gormanston

For the relevant years under review in this statement it is assumed the necessary operational and commercial requirements are in place as part of the Common Arrangements for Gas (CAG) project, to facilitate the export of surplus gas from NI (Larne storage gas) into Ireland, and export surplus gas from Ireland into NI, when required.

It is assumed for modelling purposes in the 2011 JGCS that under the CAG arrangement, the option would be available to operate the network under either the current configuration or a CAG configuration where there may be excess supplies in either jurisdiction. This assumption will continue to be reviewed in the preparation of future Statements.

Appendix 4: Energy Efficiency Assumptions[21]

National Energy Efficiency Action Plan (NEEAP)

The NEEAP for Ireland sets out the Government's strategy for meeting the energy efficiency savings targets identified in the energy White Paper (2007) and the EU Energy Services Directive (ESD). These targets include:

- The White Paper target of a 20% reduction in ROI energy demand across the whole economy by 2020, with a higher 33% target for the Public Sector; *and*
- The ESD target of a 9% reduction in energy demand by 2016;

The JGCS assumes that 50% of the NEEAP energy efficiency targets will be met for both the residential and IC sectors. This assumption is intended to reflect the increased difficulty in achieving the targeted savings within sectors where straightforward energy savings have already been achieved.

Table A3.1: NEEAP Energy efficiency savings targets

	2010 PEE[22] target (GWh)	***2016 PEE target (GWh)***	***2020 PEE target (GWh)***
Residential Sector			
Building Regulations 2002	1,015	1,015	1,015
Building Regulations 2008	130	1,425	2,490
Building Regulations 2010	0	570	1,100
Low carbon homes	0	130	395
SEI house of tomorrow	30	30	30
Warmer homes scheme	115	155	170
Home Energy Savings programme	450	600	600
Smart metering	0	650	690
Greener Homes scheme	265	265	265
Eco-design for energy appliances (lighting)	200	1,200	1,200
More efficient Boiler Standard	400	1,600	2,400
Total residential savings	2,605	7,640	10,355
Business & Commercial sectors			
SEI public sector retrofit programme	140	140	140.0
Building Regulations 2005	185	370	560.0
Building Regulations 2010	0	630	1,360.0
SEI energy agreements (IS 393)	465	685	4,070.0
SEI small business supports	160	330	565.0
Existing ESB DSM programmes	380	410	435.0
Renewable Heat Deployment programme	360	410	410.0
ACA for energy efficient equipment	100	400	800.0
Total business and commercial savings	1,790.0	3,375.0	8,340.0
Other sectors			
Transport	775	3,105	4,670
Energy Supply sector	275	300	365

[21] These energy efficiency assumptions have also been utilised in Gaslink's Network Development Statement 2011/12-2020/21

[22] Primary Energy Equivalent

Total measures identified above	5,445	14,420	23,730
White Paper target (20% reduction by 2020)			31,925
Additional measures yet to be identified			8,195

Impact on residential gas demand

The proposed energy efficiency measures for the residential sector should clearly have a material impact on annual gas demand of the residential sector. The JGCS forecast for the residential sector includes the following assumptions:

- Incremental gas demand from new residential connections should continue to reduce due to tighter building regulations and will fall to 40% of 2005/06 levels by 2012/13; *and*
- Existing residential gas demand should also reduce due to the introduction of more efficient boiler standards (e.g. condensing boilers), smart metering and the combined impact of the Low Carbon Homes, Warmer Homes & Home Energy Saving schemes.

The average annual gas consumption of all new residential customers connected during the 2005/06 gas year was approximately 12.3 MWh/y. The JGCS forecast assumes the average gas consumption of each new customer connected by 2012/13, will reduce by 62% to 4.65 MWh/y with a greater ratio of houses to apartments being connected.

The NEEAP assumes a total reduction of 4,255 GWh in residential energy demand, due to the introduction of more efficient boiler standards, smart metering and the combined impact of the Low Carbon Homes, Warmer Homes and Home Energy Saving schemes.

In addition it also identifies the potential for a further energy efficiency reductions of 1,920 GWh from the retrofitting of attic, cavity-wall and wall-lining insulation to existing houses (after adjusting for the impact of the Warmer Homes and Home Energy Savings schemes).The JGCS forecast assumes that:

- Total energy efficiency savings of 2,807 GWh in residential heat demand between 2010/11 and 2020/21 from the above measures (annual reduction of 281 GWh/y);
- Approximately 20% of this target reduction will be achieved in gas-fired residential homes, based on the gas share of residential heat in 2011, i.e. the gas share of total residential TFC after excluding the electricity and renewable components; *and*
- This would lead to a reduction of 56.1 GWh/y in residential annual gas demand, which is equivalent to 0.7% of the residential gas demand in 2010/11.

If all of the above energy efficiency measures are implemented as anticipated and achieve the assumed energy savings, then it is estimated that annual residential gas demand will reduce by approximately -0.55% over the period. This reduction is less than anticipated in previous documents due to the reduced impact of energy efficiency savings and the decrease in new dwelling units connecting to the system.

Impact on I/C gas demand

The NEEAP assumes a total reduction of 3,375 GWh in I/C gas demand by 2016, and a total reduction of 8,340 GWh by 2020. Some of this reduction may have already occurred since the 2002-2005 baseline period. The JGCS forecast assumes:

- That the total I/C energy demand will reduce by 3,375 GWh by 2016 and a further 4,965 GWh by 2020 (50% of the NEEAP target), an annual reduction of 338 GWh/y up to 2016 and 1,174 GWh/y up to 2020;
- The gas share of these reductions is assumed to be 23.1% up to 2016 and 25.6% up to 2020, based on gas share of total I/C TFC in 2011 (of 27.5%) and adjustments to exclude initiatives which are specific to electricity (e.g. ESB demand reduction programmes); *and*

- This would lead to an annual reduction of 78.0 GWh/y in I/C annual gas demand up to 2014/15, and 300.5 GWh/y from 2015/16 onwards (which is equivalent to 0.4% and 1.5% of the 2010/11 I/C annual demand respectively).