NETWORK DEVELOPMENT STATEMENT

2011/12 TO 2020/2021

gaslink
Gas System Operator

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DISCLAIMER

Gaslink has followed accepted industry practice in the collection and analysis of data available. However, prior to taking business decisions, interested parties are advised to seek separate and independent opinion in relation to the matters covered by the present Network Development Statement (NDS) and should not rely solely upon data and information contained therein. Information in this document does not purport to contain all the information that a prospective investor or participant in Ireland's gas market may need.

Contents

1. Introduction

This Network Development Statement (NDS) covers the 10 year period from 2011/12 to 2020/21. It is published by Gaslink (the Independent Gas System Operator), with assistance from Bord Gáis Networks (BGN).

Condition 11 of Gaslink's Transmission System Operator Licence requires it to produce a long term development plan. The publication of the NDS is designed to meet this obligation. The NDS serves as the Gaslink input into the Joint Gas Capacity Statement (JGCS) consultation process, which is directed by the Commission for Energy Regulation (CER) and the Northern Ireland Utility Regulator (UREGNI).

Natural gas continues to play a very important role in the energy mix of Republic of Ireland (ROI). Natural gas brings considerable economic and environmental benefits. It is cheaper than oil, has the lowest CO_2 emissions of any fossil fuel and provides the most efficient form of thermal power generation.

The NDS informs market participants about gas usage, and thereby, maximise the resulting economic and environmental benefits to the Republic of Ireland (ROI) economy. It provides existing and potential users of the ROI system with an overview of future demand, likely future sources of supply and the capacity of the existing system.

The NDS focuses mainly on the ROI transmission system, which includes both the onshore ROI transmission system and the BGÉ Interconnector ("IC") system, including:

- The two subsea interconnectors from Loughshinny and Gormanston in Ireland, to Brighouse Bay in Scotland; and
- The Brighouse Bay and Beattock compressor stations and connecting transmission pipeline, which connect the two subsea interconnectors to the Great Britain (GB) National Transmission System (NTS) at Moffat in Scotland.

The NDS also discusses other assets in the ROI system and reports on significant projects completed on the distribution system.

The Northern Ireland ("NI") and Isle of Man ("IOM") peak day and annual demands are also included in the NDS demand forecasts for completeness, as they have a material impact on the capacity of the IC system. These forecasts are based on information provided by UREGNI in NI and the Manx Electricity Authority (MEA) on the IOM.

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

July 2012

2. Executive Summary

2.1 Key Messages

- Gas demand is anticipated to grow over the next 10 years, despite increasing renewable generation capacity, increasing gas prices and greater energy efficiency.
- The ROI will continue to depend on the Moffat Entry Point and Interconnector System to provide approximately 93% of its gas demand until Corrib commences production. The Moffat Entry Point and Interconnector system may be required to fully meet ROI gas demand post Corrib, should supplies cease at existing indigenous Entry Points and no other future supply sources materialise. This demonstrates the strategic importance of this Interconnector System to the ROI.
- Shell E&P Ireland, the Corrib field operators, have indicated that Corrib supply is anticipated to commence full commercial operation in April 2015. Shannon LNG have indicated 2017 as the earliest potential date for commercial operations.
- The NDS forecasted peak day Moffat flows indicate the capacity limits of the Moffat Entry Point will be reached in 2014/15 and any subsequent years Corrib is delayed, regardless of how the gas flows are profiled. The ongoing presence of non-uniform flow profiles at the Moffat Entry Point increases the likelihood of reaching capacity limits before 2014/15.

  Bord Gáis Networks & Gaslink continue to recommend reinforcing the 50km single section of pipeline in southwest Scotland as the most appropriate and cost effective solution to provide additional capacity. This is despite the current position of the CER being that this project should not proceed at this time. Therefore, in the absence of reinforcement Gaslink and Bord Gáis Networks stress the urgency of developing appropriate demand side measures.

  Forecasted Peak Moffat flows are anticipated to reach capacity limits again in 2018/19 and all subsequent years, assuming no new supply sources materialise, supplies at the Inch Entry Point have ceased and supplies through the Corrib Entry Point have declined.
- Work is ongoing with National Grid (UK) to clarify the pressure service available from their system at Moffat (Scotland). The analysis for this statement was on the basis that a minimum source pressure of 47 barg will be available from National Grid's National Transmission System (NTS) up to and including 2014/15, and 45 barg for all subsequent years.
- Bord Gáis Networks is finalising an operating procedure with Premier Transmission Ltd (PTL), which will clarify the necessary profiling arrangements at the Twynholm Exit Point in southwest Scotland, where PTL's system connects to the Interconnector System. The capacity of the Interconnector System is influenced by the gas flow profiles at the Moffat Entry Point and Exit Points on the southwest Scotland onshore system (SWSOS), including Twynholm. The implementation of this operating procedure will enhance Bord Gáis Networks operational confidence in managing the SWSOS and provide greater certainty to NI regarding the pressure and capacity available at Twynholm.
- Regarding the ROI onshore transmission system, it has sufficient capacity to meet the gas flow requirements on 'Winter Peak Days' and 'Summer Minimum Days' for the next six to seven years. The southern part of the ROI transmission system (Cork & Waterford) may require reinforcement in 2018/19, subject to supplies ceasing at the Inch Entry Point.
- Gaslink and Bord Gáis Networks have considered strategic network reinforcement as part of the long term network development plan. The Goat Island to Curraleigh West pipeline should be a priority strategic reinforcement, as the first step in guaranteeing security of supply to all gas consumers located in the south of the country (Cork & Waterford) and consumers on the national electricity grid.

2. Executive Summary

2.2 Gas Demand

In contrast to the severe weather experienced in the winters of 2009/10 and 2010/11, the recent 2011/12 winter was a period of relatively mild weather. This was reflected in the gas demand during the 6 month period, October to March. The ROI gas demand for the current gas year peaked on the 16th December, which was 13.9% less than the previous year's peak day. The total annual gas demand for the current gas year is anticipated to contract by 11.3% on the previous year (2010/11).

The annual gas demand in 2010/11 was slightly down on the previous year's levels, primarily due to contraction in the power generation sector. Fuel price movements resulted in coal fired plant becoming the most competitive thermal generator in the Single Electricity Market (SEM) 'Merit-Order' all year round. This is still the case in 2011/12.

Industrial & Commercial (I/C) gas demand grew in the previous two gas years despite the significant economic slowdown. The I/C gas demand for the current year is anticipated to be on par with the previous year's demand.

ROI gas demand is anticipated to grow over the next 10 years, despite increasing renewable generation capacity, increasing gas prices, the economic slowdown and greater energy efficiency.

Gas fired power plants will continue to play a very significant role in the Irish electricity market. Gas fired generation's current level of participation in the thermal generation mix is anticipated to increase in the medium to long term, in response to rising carbon prices. This will impact on the competitiveness of coal, peat and oil fired generation.

Gas fired power plants are best placed to complement both domestic and European energy policy goals. The baseload gas fired plants are the most efficient generators in the Irish thermal plant portfolio. Natural gas is the cleanest fossil fuel and gas fired plants are best able to provide the flexibility required to support the ever increasing renewable generation capacity on the electricity grid.

I/C gas demand is anticipated to experience further growth as the economy recovers. Residential gas demand is expected to contract slightly, in response to increasing energy efficiency, for example the introduction of more efficient domestic gas boilers.

While this NDS has assumed no gas demand for the transport sector, Natural Gas Vehicles (NGVs) could potentially be a new growth area for gas demand in future years. Future statements will monitor and consider any developments in this sector.

2.3 Gas Supplies

The Moffat Entry Point and Interconnector System supplied 93% of ROI gas demand in 2010/11, with similar levels of supply participation being observed in the current gas year. The ROI will continue to depend on the Moffat Entry Point and Interconnector System to provide over 90% of its gas demand until Corrib commences production and is likely to revert to this level of dependency post Corrib. The Moffat Entry Point and Interconnector system may be required to fully meet ROI gas demand post Corrib, should supplies cease at existing indigenous Entry Points and no other future supply sources materialise.

There is a some uncertainty surrounding the timing of certain proposed supply projects and the future of an existing supply source on the Island. PSE Kinsale Energy has indicated existing storage operations may cease after 2013/14, followed by total cessation of Inch supply after 2016/17.

The Corrib field operators, Shell E&P Ireland, have indicated the commissioning of Corrib gas is anticipated to commence in October 2014 for a period of 6 months followed by full commercial operation from April 2015.

Shannon LNG have indicated their proposed LNG facility maybe available from 2017. The developers of the two storage projects in the Larne area continue to progress feasibility studies regarding their respective salt cavity storage projects.

2.4 Network Development

The network analysis detailed in chapter 6 examines the capacity of the ROI onshore transmission system and onshore Scotland system (including the subsea Interconnectors). Results indicated the ROI onshore transmission system has sufficient capacity to meet the gas flow requirements on 'Winter Peak Days' and 'Summer Minimum Days' for the next six to seven years.

Pressure violations were observed in the southern part of the transmission system (Cork and Waterford) for the 1-in-50 peak days in the later years of the forecast period; the occurrence of such low pressures were as a result of the unavailability of supplies from the Inch Entry Point. Future statements will continue to monitor this potential issue, and recommend reinforcement if and when required.

Last year the NDS (Gaslink), JGCS (CER & UREGNI) and Winter Outlook (Gaslink) all noted the capacity limits of the Moffat Entry Point (Interconnector System) will be approached over the coming winters and will be reached in 2013/14, should the forecasted peak demands occur. This year's NDS indicates the same constraint will occur, albeit one year later in 2014/15, due to a change in date regarding the cessation of existing Celtic Sea storage operations. This constraint is anticipated 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 flow profiles at the Moffat Entry Point increases the likelihood of reaching capacity limits before 2014/15.

Bord Gáis Networks and Gaslink continue to recommend reinforcing the 50km single section of pipeline in southwest Scotland as the most appropriate and cost effective solution to resolve the potential constraint. The current position of the CER is that this project should not proceed at this time and, accordingly, Bord Gáis Networks & Gaslink stress the urgency of developing appropriate demand side measures.

Gaslink and Bord Gáis Networks believe strategic network reinforcement should be considered as part of the long term network development plan. A recent event in the southern section of the network, demonstrated that the loss of service through a section of the Ring-Main is a reality. The Goat Island to Curraleigh West pipeline should be a priority strategic reinforcement, as the first step in guaranteeing security of supply to all gas consumers located in the southern half of the country and consumers on the national electricity grid.

It should be noted that any future (post 2011/12) network investment referenced in this document would be subject to regulatory approval by the CER. Bord Gáis Networks currently awaits a final decision on the Price Review 3 (PR3) approved spend.

Gaslink note that the appropriate final decision on the PR3 spend should provide a sufficient allowance for investment, to guarantee the supply capacity and security to meet the ROI's future demand requirements, while ensuring the continued safe, secure, reliable, efficient and economic operation of the gas network.

3. The BGÉ ROI Network

3.1 Overview of the Existing BGÉ ROI Gas Network

The BGÉ ROI gas network consists of approximately 13,224kms of high pressure steel transmission pipeline and lower pressure polyethylene distribution pipelines, Above Ground Installations (AGIs), District Regulating Installations (DRIs) and compressor stations in the ROI and Scotland. The integrated supply system is sub-divided into 2,149kms of high pressure sub sea & cross-country transmission pipes and approximately 11,076kms of lower pressure distribution pipes. The distribution network operates in two tiers; a medium pressure and a low pressure network. The high level system statistics are summarised in Tables 3.1 and 3.2 and illustrated in Figure 3.1

Table 3.1: ROI Pipeline Summary Statistics

Location	Current MOP* Pressure (barg)	Total Length (km)	Max Nominal Pipe Diameter (mm)
Onshore ROI	85.0	161	650
Onshore ROI [1]	75.0	60	450
Onshore ROI	70.0	1,133	900
Onshore ROI	40.0	92	500
Onshore ROI	37.5	15	600
Onshore ROI	19.0	153	600
Onshore ROI	7.0/4.0	16	600
Subtotal	N/A	1,630	900
Scotland	85.0	110	900
Subsea	148.0	409	750
Total Tx	N/A	2,149	n/a
Onshore Ireland Dx	>100mBar	6,646	315
Onshore Ireland Dx	<100mBar	4,430	315
Total Dx	N/A	11,076	315

[1]Portion of SNP in ROI MOP = 75Barg;

Table 3.2: Bord Gáis Installation Summary

Location	No. of AGI[1] Installations	No. of DRI Installations	No. of Compressor Stations	Compressor Power[2] (MW)
Total ROI	168	877	1	8.8
Total Scotland	7	0	2	61.6
Total	175	877	3	70.4

[1]AGIs include pressure regulating, metering and block valve stations
[2]Refers to duty power of station and excludes standby compressors

The BGÉ ROI transmission system includes the IC system and the onshore ROI system. The IC system includes two subsea Interconnectors to Scotland; two compressor stations at Beattock and Brighouse Bay, and 110km of onshore pipeline between Brighouse and Moffat in Scotland.

The IC system connects the onshore ROI system to the GB National Transmission System (NTS) at Moffat in Scotland. It also supplies gas to the NI market at Twynholm and the IOM market via the 2nd subsea Interconnector (IC2). The IC system is also used to provide a gas inventory service to ROI shippers (see Figure 3.1)

The onshore ROI system consists of a ring-main system between Dublin, Galway and Limerick, with cross-country pipelines running from the Ring-Main to Cork, Limerick, Waterford, Dundalk and the Corrib Bellanaboy terminal in Mayo. It also includes a compressor station at Midleton.

3.2 New Towns and New Connections

Following on from the connection of numerous new towns in recent years, Bord Gáis Networks completed the Phase 3 Towns report on behalf of Gaslink in 2009, which examined the feasibility of connecting a further 39 towns across various regional groupings to the network.

In Quarter 1 2010, the CER approved the extension of the gas network to Tipperary Town, Co. Tipperary; Kells, Co. Meath; and Kinsale and Innishannon, Co. Cork. In addition, in Quarter 3 of 2010, the town of Macroom Co. Cork was also resubmitted to the CER and approved, on the basis of a large new production development adjacent to this town.

Figure 3.1: Overview of the ROI Transmission System

3. The BGÉ ROI Network

During 2011 Kinsale, Tipperary, and Kells were connected to the natural gas network and phase 1 of the network extension to Macroom was also completed, allowing the connection of the Town's anchor customer to the network.

Gaslink will continue to review the feasibility of connecting new towns on an ongoing basis.

In 2011 Gaslink and Endesa Ireland entered into a Large Network Connection Agreement to commence the construction of a 46.5km high pressure steel pipeline to fuel the 'Combined Cycle Gas Turbine' (CCGT) power plant that is currently being developed at Great Island, Co. Wexford. Planning permission was granted by An Bord Pleanála to Bord Gáis Networks in May 2012 for construction of the cross-country pipeline. Subject to receiving all the remaining necessary statutory approvals, it is anticipated that construction on the pipeline will commence in Q3 2012. The pipeline has also been designed to cater for future gas demand in the South East region which will bring many economic and environmental advantages to the area.

3.3 System Reinforcement

It is necessary from time to time to reinforce the existing gas transmission system to facilitate local development and other such works. Reinforcement projects that were either completed during 2010/11 (or are in the final phases of commissioning) include:

- Substantial completion of capacity upgrades to Hollybrook AGI (Bray) and Loughshinny AGI (Rush),
- Installation of volume control in Beattock compressor station to increase the operating envelope of the turbo compressor units in anticipation of future requirements on the network.
- The twinning of the Curraleigh West to Midleton Pipeline and the construction of the associated Lochcarrig Lodge to Midleton Pipeline has transferred the Cork area transmission system to the discharge side of Midleton compressor station. This has brought significant benefits in terms of enhanced pressures to the customers connected to the system.

The old Aghada power station and the Whitegate and Long Point AGIs remain connected to the transmission system between Midleton compressor station and the Inch Entry Point. Any Inch gas in excess of these demands will be compressed at Midleton into the 70-barg system in the Cork area.

Upgrades to Cadburys, Suir Road, Kilbarry, Blakestown, Raffeen AGIs are scheduled to be completed in 2012. Further capacity upgrades to Cork Gas, Fairview and Seapoint AGIs have been identified and are scheduled to commence detailed design in early 2013.

17kms of reinforcement to the distribution network was carried out during 2012. One of the more significant projects completed last year was the Clonshaugh to Stockhole reinforcement project which consisted of 4.2km of 250mm of polyethylene pipe. The pipeline was required to reinforce the network on the north side of Dublin. Network reinforcement requirements will continue to be monitored into PR3 with necessary localised projects rolled into annual programmes of work.

3.4 System Refurbishment

There is a continuous programme 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 carried out in conjunction with reinforcement work (where possible), to minimise overall costs and to limit disturbance to local communities.

Increases in population density in the vicinity of transmission pipelines may require preventative measures to be taken such as the diversion of pipelines, the provision of impact protection and the installation of "heavy-wall" pipe. The Dublin 4 pipeline replacement project was completed in 2010.

The following transmission system refurbishment and diversion projects are planned for the 2011/12 gas year:

- Detailed integrity and capacity assessments have been carried out on the Limerick 19 barg network which has identified the need to refurbish and reinforce the network. Front-end engineering work is progressing with a view to construction commencing next in 2013.
- Santry to Eastwall pipeline replacement project; Optimal solution for the refurbishment of the 6.5km Santry to Eastwall pipeline is scheduled to commence construction in Q3 2012.
- Waterford pipeline replacement project; an optimal solution for the refurbishment of the 4.5km Waterford City pipeline is in progress.
- Ballymun Interchange pipeline replacement project; preliminary engineering work is progressing with a view to construction commencing in 2013.

Rolling programmes planned to commence in 2013 (subject to CER PR3 approval) are as follows:

- Heating system refurbishment at circa 25 AGIs (boilers and waterbaths) are scheduled to commence in 2013; and
- Refurbishment of c. 350 DRI and IC installations.

4. Demand

4.1 Points of Interest

4.1.1 2011 Mild Weather Condition

Based on a degree day comparison 2011 was 23% warmer than 2010 and 7% warmer than the previous 69 year average despite a colder than average January and March combined with a colder summer period. The winter of 2011/12 was 9% warmer than the 69 year average and 23% warmer than the 2010/11 winter period. The coldest day in 2011/12 to date was 30% warmer than the 2010/11 peak which was the coldest day on record.

Mean wind speeds for the year were above average, measuring between 7 and 15 knots (13 and 27 km/h). Wind powered generation was 64% higher in 2011 than 2010. While there was a growth in the installed wind powered generation capacity, the majority of the growth in wind powered generation can be attributed to the increased wind experienced in 2011.

4.1.2 Moyle Electrical Interconnector Outage

An outage on the 500MW Moyle electrical interconnector lasting a little over 6 months had the potential for higher gas demands in late 2011 due to the inability to import electricity to the SEM.

A fault was recorded on one of the two cables on the 26th June 2011 with a separate fault recorded on the second cable on the 24th August. Repair works were carried out over the following six months and it was returned to full operation in mid February 2012.

Modelling indicates that the loss of the Moyle IC could have increased the ROI electricity generation sector's peak day gas demand by 13% on an average year peak day and by 8% on a 1-in-50 year peak day. Actual peak day gas demand in the electricity generation sector for 2011/12 was -14% lower than that estimated for an average year with the Moyle IC unavailable. The reduction in demand is due to warmer than average peak day temperatures and higher than average wind levels, resulting in lower electricity demands and higher wind powered generation.

Mutual Energy Ltd (MEL) has recently announced the reoccurrence of a fault on the north cable of the Moyle Interconnector, resulting in an outage with transfer capacity reduced to 250 MW (half the full capacity of the Moyle Interconnector). MEL also acknowledge they are preparing for the potential reality of recurring faults. It is currently unknown how long the existing outage will last.

4.2 Historic Peak Day Demand – 2006/07 to 2011/12

4.2.1 Overall ROI Demand

Total ROI peak day gas demand for 2011/12 was -14% lower than the 2010/11 peak day demand. The demand decrease is driven primarily by reductions in the power generation and residential sector demands.

The reduction in peak day gas demand was driven primarily by a drop in the electricity generation and residential sector gas demands with a smaller reduction in the I/C sector in 2011/12 compared to 2010/11. The peak day gas demand has grown by 0.7% per annum on average since 2006/07. There has been significant growth and contraction in the peak day gas demand over this period.

It is worth noting that, although the 2010/11 peak day gas demand was less than the 2009/10 peak, 2010/11 witnessed a prolonged period of near peak day demands. In 2009/10 6 days were within 90% of the peak day demand and 3 days were within 95% of the peak, including the peak day itself. 2010/11 however saw a prolonged demand period where 20 days were

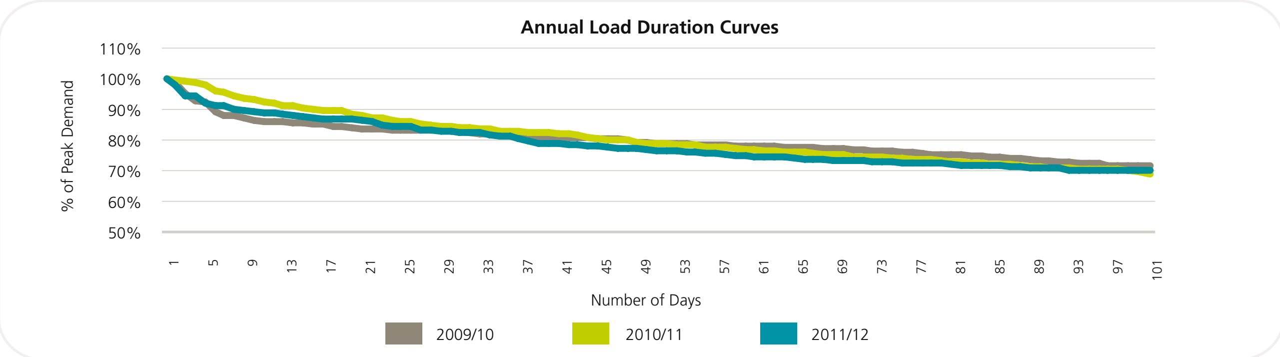
Table 4.1: Historic ROI Peak day Gas Demand (Actual Demands)[1]

	2006/07 (GWh/d)	2007/08 (GWh/d)	2008/09 (GWh/d)	2009/10 (GWh/d)	2010/11 (GWh/d)	2011/12 (GWh/d)
Peak day						
Power[2]	111.2	119.7	126.4	134.3	132.2	116.3
I/C	43.1	43.4	44.4	46.3	49.6	47.7
RES[1]	50.4	52.5	56.7	67.0	64.2	47.7
Total	204.7	215.6	227.5	247.6	246.0	211.7

[1]Actual demands shown (no weather correction), with RES estimated as % of NDM demand

[2]Power sector demand includes the gas demand for those I/C connections which generate electricity for their own use less process gas

Fig. 4.1: Historical Daily BGÉ System Gas Demand Load Duration Curve



within 90% and 11 days were within 95% of the peak day demand. Of the 20 days within 90%, 19 of these occurred within 21 days of the peak. 2011/12 has seen a continuation of this trend with 7 days within 90% of the peak day demand. This trend is shown in Figure 4.1.

4.2.2 Power Generation Sector

The 2011/12 power generation sector peak day is -12.0% lower than 2010/11 figures. The reduction in demand is due to increasing gas prices, a reduction in total electricity demand and an increase in wind generated electricity.

The 2010/11 peak electricity demand increased by 2% from the 2009/10 peak demand while the 2011/12 peak contracted by -8.8% on the 2011/12 peak. The 2010/11 peak of 5,090MW occurred on the 21st December 2010 and reflects the highest demand recorded on the system to date. The 2011/12 peak of 4,640 MW represents the lowest annual peak demand since 2004/05.

4.2.3 I/C Sector

The peak day demand fell by -3.8% but has increased by 2.0% per annum since 2006/07. The reduction in the peak day I/C gas demand is attributed primarily to the contraction in the NDM IC sector which fell by -20% in 2011/12 compared to the previous year. The transmission connected I/C sector recorded a growth of 3% from 2010/11 figures following very strong growth in 2010/11. The distribution connected daily metered sector showed a slight decline of -3%.

4.2.4 Residential Sector

The peak day demand contracted by -25.7% in 2011/12 compared to 2010/11. The peak day residential gas demand has grown by an annual average of 6.2% since 2006/07 to 2010/11. The significant reduction in the peak day demand is due primarily to the milder weather conditions experienced to date in 2011/12.

4.2.5 BGÉ System Demands

2011/12 BGÉ system peak day was -11.6% lower than the previous year peak. The system peak day gas demand had grown by an average of 4.1% per year to 2010/11 since 2006/07. The 2011/12 peak is the lowest system peak since 2005/06. The reduction is due primarily to the milder weather conditions and increased renewable generation.

The fall in the system peak day gas demand was due to a drop in both the ROI and NI figures as shown in Table 4.2. The reduction in the annual system demand

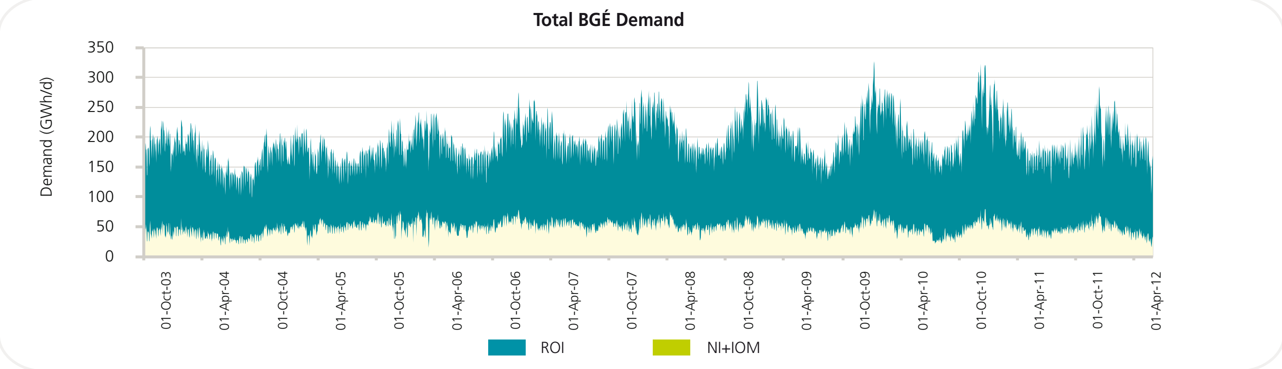
Table 4.2: Historic BGÉ Peak day Gas Demand (Actual Demands)

	2006/07 (GWh/d)	2007/08 (GWh/d)	2008/09 (GWh/d)	2009/10 (GWh/d)	2010/11 (GWh/d)	2011/12 (GWh/d)
Peak day[1]						
ROI	196.7	205.9	227.5	247.6	244.1	211.7
NI + IOM	79.0	74.8	67.7	80.0	79.3	74.1
Total	275.7	280.7	295.2	327.6	323.4	285.8

[1]Excludes shrinkage gas consumed on the peak day

4. Demand

Fig. 4.2: Historical Daily Demand on the BGÉ Transmission System



however was solely a result of a reduction in ROI demand offsetting an increase in NI annual gas demand.

Figure 4.2 presents the historical peak day system demand. It is worth noting that while the 2010/11 peak day gas demand was less than the 2009/10 peak, there were a greater number of peak events seen within a short period of time. In 2009/10 there were 3 events within 95% of the peak day and 5 events which were within 90%. 2010/11 saw 7 events within 95% of the peak and 15 events which were within 90%. 14 of the 15 events within 90% occurred within a 16 day time range of the peak day.

These demands occurred despite unscheduled outages at a number of gas fired power stations. Total daily gas demands over the period would have been higher had these stations been available. Figure 4.2 also illustrates the increasing range between peak and minimum demand days, primarily due to the demand volatility in the power generation sector, which is a consequence of increasing wind generation, fuel price movements and the construction of new gas fired plants. This increasing variability is anticipated to continue in future years, placing an even greater requirement on system flexibility, particularly the compressor stations in Scotland, which are likely to approach their operating limits more frequently.

4.3 Historic Annual Demand – 2006/07 to 2011/12

4.3.1 Overall ROI Demand

The annual gas demand is presented up to and including 2011/12 gas year. The year to date data for 2011/12 has been forecast forward to provide an approximation for 2011/12 annual gas demand. The 2010/11 annual gas demand fell by -4.3% compared to 2009/10 and 2011/12 are forecast to be a further -11.3% below 2010/11 figures. The reduction can be contributed largely to a reduction in the power generation sector gas demand with a smaller reduction evident in residential gas demand.

4.3.2 Power Generation Sector

2010/11 annual gas demands were -10% lower respectively compared to 2009/10 and the 2011/12 forecast annual gas demand is anticipated to be -15.1% lower than 2010/11.

Table 4.3: Historic ROI Annual Gas Demand (Actual Demands)[1]

	2006/07 (GWh/y)	2007/08 (GWh/y)	2008/09 (GWh/y)	2009/10 (GWh/y)	2010/11 (GWh/y)	2011/12[3] (GWh/y)
Annual						
Power[2]	34,688	37,758	36,007	39,338	35,432	30,085
I/C	10,486	10,507	10,415	10,409	11,954	12,226
RES	7,716	8,239	8,312	8,492	8,340	7,098
Total	52,890	56,504	54,734	58,239	55,726	49,409

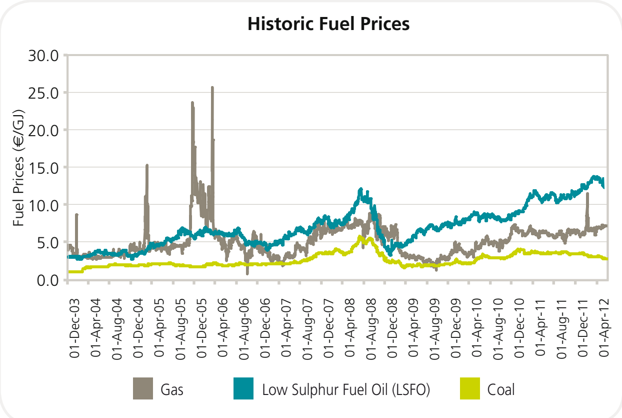
[1]Actual demands shown (no weather correction), with RES estimated as % of NDM demand
[2]Power sector gas demand is amended to account for those I/C connections which generate electricity for their own use less process gas
[3]End of year totals forecast from year to date totals

Historical fuel prices are shown in Figure 4.3. Gas prices have remained higher relative to coal prices since 2009. This coal to gas price ratio has enabled coal plants to maintain a favourable position in the despatch order. The year to date demand for 2011/12 is -2.9% lower than the same period for 2010/11. 2010/11 annual electricity demand fell by -1.2% compared to 2009/10 demand. The annual demand has reduced by -1.1% per annum on average since 2006/07.

The year to date wind powered generation is 43% higher than over the same period in 2010/11. Wind powered annual electricity generation increased by 29.6% in 2010/11 compared to 2009/10. This increase is due in part to new generation becoming available but is mainly due to a return to more favourable wind speeds following a lull in 2009/10.

It is to be noted that a portion of the gas demand currently attributed by metering to the power sector is in fact auto producers using gas for process use and not for use in generating electricity. Auto producers are those connections which use gas to generate electricity for their own use. This portion of gas demand accounted for approximately 1% of the annual power sector gas demand in 2010/11. There is no separate metering system in place to accurately quantify the amount of gas which is currently used for non-power generation within these facilities. The approximate amount of production gas has been deducted from the 2010/11 power sector gas demand and has been added to the transmission connected I/C sector. Analysis is currently ongoing to identify the amount of future process gas which is to be attributed to non-power generation sectors

Fig. 4.3: Historical Fuel Prices



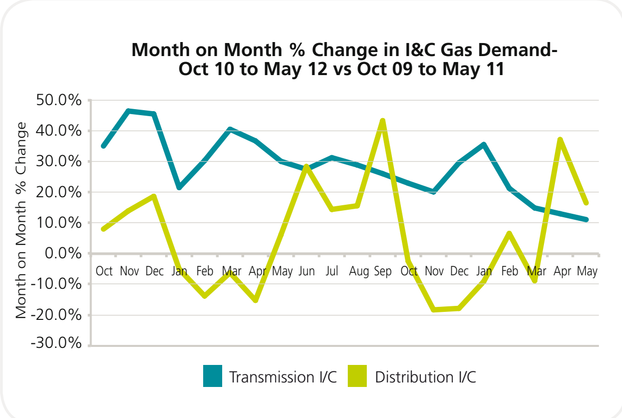
4.3.3 I/C Sector

The 2010/11 annual I/C gas demands recorded a growth of 14.6% over the 2009/10 demands and has grown by 3.3% per annum since 2006/07. The 2011/12 annual demands are forecast to increase by a further 2.3% over 2010/11 figures.

The growth in annual I/C gas demand in 2010/11 was driven primarily by the growth in the transmission connected I/C sector. Gas demand for transmission connected sites grew by 32% in 2010/11 against the previous year. Both the distribution connected daily metered and non-daily metered sites grew in 2010/11 by 6% and 4% respectively. Figure 4.4 displays the growth trend in both the transmission and distribution connected I/C sites for a month on month comparison of the period October 2009 to May 2011 against October 2010 to May 2012. The transmission connected I/C demand growth is shown to be returning to a steadier growth rate following the high growth rates seen in early 2010/11. The negative demand growth in the distribution connected I/C sector for January to May 2011 reflects a return to the demand levels of 2009 following a growth in demand recorded for the same period in 2010.

The decision by auto producers to use gas for production processes in addition to electricity production, as discussed in section 4.3.2, has increased the I/C gas demand. This activity accounted for approximately 5% of the I/C gas demand in 2010/11 and will contribute to approximately 10% of IC demands in 2011/12.

Fig.4.4: I/C Gas Demand Monthly Growth by Connection Type



4. Demand

Table 4.4: Residential Gas Demand per Customer

	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12[3]
No. of customers						
On 1st October	538,822	571,485	595,740	609,034	614,973	620,292
On 30th September	571,485	595,740	609,034	614,973	620,292	624,497
Customer growth	32,663	24,255	13,294	5,939	5,319	4,205
Average for Gas Yr[1]	555,154	583,613	602,387	612,004	617,633	622,395
RES Demand (GWh/y)						
Total RES demand	7,716.1	8,238.5	8,311.8	8,491.5	8,340.0	7,097.7
Demand per customer[2]	0.0139	0.0141	0.0138	0.0139	0.0135	0.0114

[1]Average for Gas Yr = Average number of residential customers connected to the distribution system over the course of the gas year (i.e. the average number of customers at the start and end of gas year)

[2]Per customer = Average residential annual gas demand per customer (before weather adjustment)

[3]End of year totals forecast from year to date totals

4.3.4 Residential Sector

The 2010/11 residential annual gas demands decreased by -1.8% against 2009/10 figures and the 2011/12 residential annual gas demand is forecast to fall a further -14.9% below 2010/11 figures. Annual residential gas demand had increased on average by 2.0% per annum over the period 2006/07 to 2010/11.

The demand figures shown in Table 4.4 reflect the impact of slowing connection numbers, a milder 2011/12 heating season and a reduction in average energy demand per customer. Despite a prolonged period of cold weather in winter 2010/11, the average annual weather conditions were milder than those in 2009/10 due to a significantly milder 2011. 2011/12 has been significantly milder than the long run average winter conditions.

The average annual energy demand per customer is -2.7% lower in 2010/11 than in 2009/10 and has fallen by -0.7% on average each year since 2006/07. This trend is expected to continue in 2011/12 with a -15.5% fall in energy demand per customer. This trend reflects the ongoing economic situation coupled with an impact from energy efficiency savings and warmer than average weather conditions.

The growth in residential connection numbers has slowed significantly in recent years from over 32,000 new connections in 2006/07 to a little over 5,000 in 2010/11 and an estimated 4,000 in 2011/12. The decrease in new connections reflects the impact of the current economic recession.

4.3.5 BGÉ System Demands

Table 4.5 presents the annual BGÉ System gas demands since 2006/07. 2010/11 BGÉ system annual gas demand contracted -2.5% against 2009/10 figures with annual demand increasing by 0.2% per annum since 2006/07. Forecast annual demands for 2011/12 are approximately -10% down on 2011/12 figures in both ROI and NI.

4.3.6 ROI Annual Primary Energy Demand

Total primary energy requirement (TPER) grew marginally in 2010 above 2009 figures increasing to 15,089 kTOE but has contracted in 2011 to 14,174 kTOE. In 2011 coal and renewable energy showed an increase on 2010 figures while peat, oil gas and electrical imports all fell. Figure 4.5 indicates a continuing decline in the TPER following its maximum in 2008. Gas now accounts for 30% of ROI TPER as shown in Figure 4.6 with oil accounting for the majority of energy demand at 50%.

Table 4.5: Historic Annual Gas Demand (Actual Demands)

	2006/07 (GWh)	2007/08 (GWh)	2007/08 (GWh)	2009/10 (GWh)	2010/11 (GWh)	2011/12 (GWh)
Annual						
ROI	52,890	56,504	54,734	58,239	55,726	50,241
NI+IOM	20,216	19,294	18,022	17,232	17,852	15,893
Total	73,106	75,798	72,756	75,471	73,578	66,055

The actual year to date 2011/12 gas demand has been forecast forward to provide an approximation for 2011/12 annual gas demand.

Fig.4.5: Analysis of Historical ROI TPER

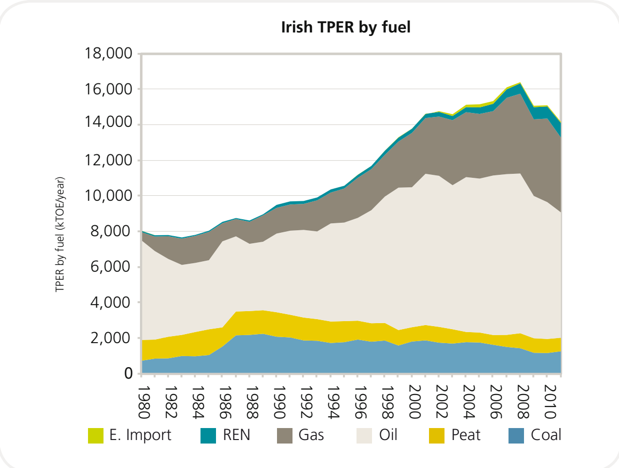
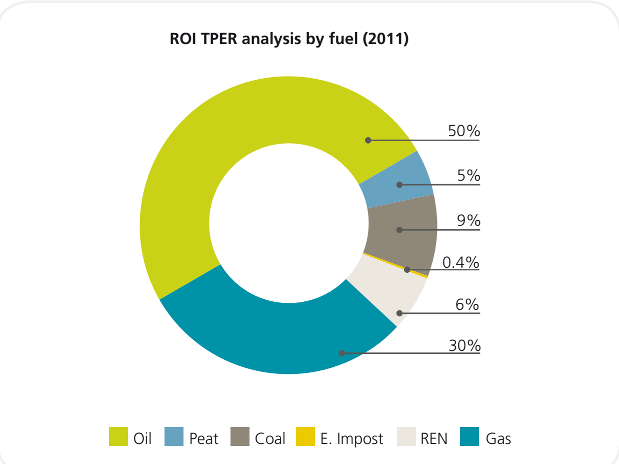


Fig.4.6: Breakdown of ROI TPER for 2011



Total final energy consumption (TFC) fell by -7% in 2011 from 2010 figures. This continues the reduction of -21% in 2010 consumption compared to 2009. All subsectors recorded a fall in 2011 consumption figures compared to 2010.

4.4 Forecast ROI Gas Demand

The NDS forecasts future gas demand by examining the possible individual power, I/C and residential sector gas demands. A number of external data sources are referenced in this process along with additional sector specific assumptions.

Annual ROI gas demand is anticipated to increase by 17% by 2020/21, at an average rate of 1.8% per annum. The 1 in 50 peak day demand is expected to grow by 11% to 2020/21 with an annual growth rate of 1.2%.

4.4.1 ROI Power Sector Forecast

Both peak day and annual power sector gas demands are expected to increase over the period to 2020/21. This growth is supported by increasing electricity demands, more favourable cost of gas fired generation and the introduction of the Large Combustion Plant Directive in 2016.

4.4.1.1 Electricity Demands

The NDS assumes future electricity demands as per EirGrid and SONI's All Island Generation Capacity Statement 2012-2021. This report anticipates annual ROI electricity demands will grow by 13% to 30,668 GWh by 2020 at a yearly average of 1.4%. Average year peak electricity demands are also expected to grow by 11% to 5,114 MW, with an annual average growth of 1.1%.

4.4.1.2 Environmental Policies

The implementation of the Large Combustion Plant Directive in 2016 will impact on those generation stations with higher emissions. It is anticipated that coal fired generation and older less efficient generation stations will limit their annual running hours in order to comply with the requirements of the regulations. This may initially lead to higher prices for electricity imports from the UK due to the high ratio of coal fired generation in the UK system and hence reduce imports to ROI. It is anticipated that gas fired generation will benefit from higher efficiencies and lower carbon costs.

4.4.1.3 Renewable Generation

The expectations regarding the deployment of wind powered generation is also in line with EirGrid and SONI's current assumptions. It is anticipated that installed wind powered generation in ROI will increase from 1,629MW in 2011 to 3,918MW in 2020. This represents a 154% increase in total wind generation over the period. Such an increase would lead to a reduction in gas demand within the electricity generation sector. Any reduction may be offset by the need to maintain a spinning reserve to compensate for unexpected shortfalls within wind powered generation. Such a need for spinning reserve would most likely continue to be provided by gas fired turbines due to their flexibility and reliability.

4. Demand

4.4.1.4 Generation Mix

The NDS assumptions regarding the future delivery and retirement of electricity generation stations are presented in Table 4.6. These assumptions are based on the All Island Generation Capacity Statement. Some stations have been excluded due to the possibility that not all the projects identified in the statement would be delivered.

It is assumed that the period to 2021 will see a net increase of 289MW of gas fired generation in operation on the island of Ireland. This additional generation may result in an increase in gas demand but the impact of this new generation capacity may simply push older less efficient gas fired generation stations further along the merit order to a position where they would be dispatched less frequently.

It is anticipated that annual gas demand will reduce slightly in 2012/13 due to the commissioning of the East – West electricity interconnector. The East – West electricity interconnector will have 500MW capacity connecting the transmission systems of Ireland and Wales and is due for completion in late 2012.

4.4.1.5 Generation Dispatch Order

The order in which electricity generation stations are called upon to generate is dependant upon their short run marginal cost (SRMC). This cost is reflective of the cost to generate 1MW of electricity. Some generators, such as wind powered generation and those with public service obligation status, receive a priority dispatch status and so are positioned highest on the merit order.

The SRMC of a plant is a function of the cost of its fuel, generation efficiency and the cost of carbon. Presently favourable coal prices relative to gas are expected to continue in the short term ensuring coal fired stations remain high on the dispatch order. Increasing coal prices later in the forecast combined with an increasing cost of carbon is assumed to erode coal's position on the dispatch order, and gas fired generation will see an increase in demand.

4.4.1.6 Future Gas Demands

The annual power sector gas demand is anticipated to increase by 24% over the period to 2020/21 at an annual average growth rate of 2.4%. This growth rate is higher than the forecast electricity demand growth rate due to the increase in gas fired generation within the generation mix and the more favourable position of gas fired generation in later years with increasing carbon and coal prices. The commissioning of the Great Island combined cycle gas turbine in October 2013 along with continued growth in electricity demands, the phasing out of the peat PSO levy and more favourable gas price ratios, will all contribute to growth in annual gas demand from 2013/14.

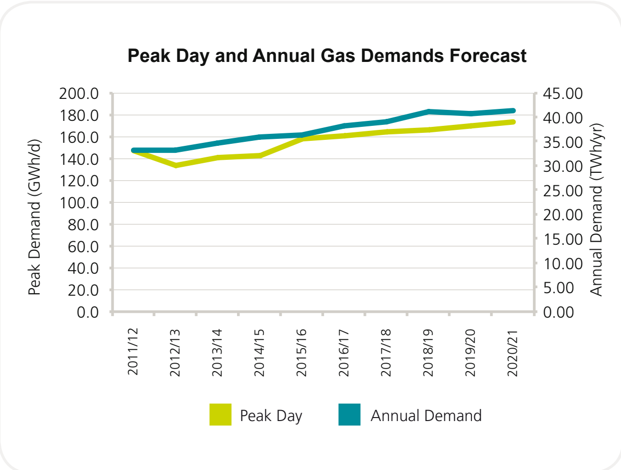
The peak day electricity demand is defined here as the level of demand which would occur once in every 50 years. The forecast for this peak day electricity demand has been estimated by applying EirGrid and SONI's peak annual electricity demand growth rate to the actual electricity demand of 5,090MW which occurred in December 2010 and which is assumed to reflect a one in 50 year peak day demand. The peak day power sector gas demand is forecast to rise by 18% over the

Table 4.6: New and Retired Power Station Assumptions

Name	Type	Export (MW)	Start Date	Location
New				
Great Island	CCGT	431	Oct 2013	Co. Wexford
Nore	OCGT	98	Jan 2014	Co. Kilkenny
Athlone Cuilleen	OCGT	98	Jan 2015	Co. Westmeath
Suir	OCGT	98	Jan 2016	Co. Tipperary
Total		725		
Retiring				
Great Island	LSFO	212	Sep 2013	Co. Wexford
Tarbert (1,2 &3)	LSFO	349	Dec 2013	Co. Kerry
Marina	OCGT	85	Sep 2014	Co. Cork
Tarbert (4)	LSFO	241	Dec 2020	Co. Kerry
Total		887		

period to 2020/21 at an annual average growth rate of 1.8%. The peak day gas demand is anticipated to fall in 2012/13 due to the commissioning of the East – West electrical interconnector but will continue to show growth from 2013/14.

Fig.4.7: Peak Day and Annual Gas Demand Forecast



4.4.2 Forecast I/C Gas Demand

The future Industrial and Commercial (I/C) gas demand forecast is generated by examining the previous years gas demand for all transmission and distributed connected sites which is then grown forward in line with anticipated connection numbers and forecast Gross Domestic Product (GDP) as appropriate.

The transmission connected I/C demand growth is forecast for the first six years using anticipated new connection numbers and associated gas demand. It then employs a rate equal to 80% GDP for the period after the initial six years. The distribution connected I/C gas demand growth rate is linked to 80% GDP growth rate for all years.

GDP forecasts are as per the ESRI Quarterly Economic Commentary (QEC) Winter 2011/Spring 2012 Report combined with further long range GDP forecasts also provided by the ESRI. It is anticipated that GDP will grow by 0.9% in 2011/12 and the growth rate will continue to increase until 2015/16 when it will settle to an average growth of 3.3% per annum.

Energy efficiency savings for all I/C sites are assumed as per the National Energy Efficiency Action Plan (NEEAP). It is estimated that 50% of the savings will be achieved which results in 33 GWh/y up to 2015/16 and then increase to 133 GWh/y for each year onwards.

The annual I/C gas demand is forecast to grow by 17% by 2020/21 at an average growth rate of 1.7%. The majority of the growth is anticipated within the transmission connected I/C sites. The distribution connected sites are also expected to show more moderate growth. The 1 in 50 year peak day I/C gas demand is expected to grow at the same rate as the annual demand.

The forecast peak day and annual gas demands of the I/C sector are summarized in Appendix No.1, and the assumptions in relation to the I/C energy efficiency savings are explained in more detail in Appendix No.3.

4.4.3 Forecast Residential Gas Demand

Future residential sector gas demands are estimated using the most recent actual residential sector gas use and forecast connections, energy demand per unit, energy efficiency savings and disconnections over the period.

The forecast of new residential customer numbers is shown in Table 4.7. It is assumed that connection number growth will be relatively slow up until 2013/14 after which connection numbers are expected to grow steadily to 2020/21. The total number of residential customers is expected to grow from 620,292 at the start of 2011/12 to 693,223 at the end of 2020/21.

Table 4.7: New Residential Connection Assumption by Gas Year

	2011 /12	2012 /13	2013 /14	2014 /15	2015 /16	2016 /17	2017 /18	2018 /19	2019 /20	2020 /21
New	1,200	1,200	1,650	3,825	4,500	4,500	4,500	5,500	6,000	6,500
One-off	4,750	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Disconnections	-1,120	-1,167	-1,247	-1,607	-1,719	-1,719	-1,719	-1,883	-1,965	-2,048
Total	4,830	5,033	5,403	7,218	7,781	7,781	7,781	8,617	9,035	9,452

4. Demand

The combination of improved building regulations for new housing, increased energy efficiency savings for existing housing and the continuing economic uncertainty are assumed to continue the decrease in total gas demand per unit. It is assumed that the trend of dropping gas demand per customer over recent years will continue. 50% of the energy efficiency savings identified under the NEEAP document are assumed to take effect over the forecast period. These assumptions combine to reduce the gas demand per unit from 13.3 MWh/y in 2011/12 to 11.3 MWh/y in 2020/21.

The annual residential sector gas demand is expected to reduce by -6% over the period to 2020/21 with an annual average of -0.7%. The peak day gas demand is assumed to contract by the same amount. Despite the contraction in the peak day demand, the residential sector gas demand will continue to remain the second highest sectoral demand on the peak day behind power generation.

4.5 Sensitivity Analysis

A sensitivity analysis was used to further examine the impact of the assumptions around forecast GDP and residential connection numbers. This analysis reflects the effect of a variance in either of these assumptions.

The analysis shows that varying the GDP assumptions by +/- 100% along with a +/- 50% variation in new transmission I/C connection assumptions has a relatively small impact on total ROI gas demand.

Varying the assumptions regarding new residential connection numbers by +/- 100% also had an negligible impact on total ROI gas demand.

4.5.1 GDP Sensitivity

GDP is used within the forecasting model to estimate the future growth in the distribution connected I/C sector. The transmission connected I/C sector gas demand is estimated through a combination of forecast new connections for the first 6 years and is then projected forward using GDP for later years.

A sensitivity analysis around GDP assumptions examined the impact of a high and low GDP growth rate combined with a high and low transmission connected I/C site growth rate. A high and low GDP growth rate was assumed as a 100% increase and decrease from the base case GDP assumptions. The high and low transmission connections were assumed as plus one connection and minus one connection per year from the assumptions of the base case scenario. The assumptions and their impact are outlined in Table 4.8.

Table 4.8: GDP Sensitivity

	2011 /12	2012 /13	2013 /14	2014 /15	2015 /16	2016 /17	2017 /18	2018 /19	2019 /20	2020 /21
Base GDP	0.9	1.95	2.83	3	3.23	3.31	3.31	3.31	3.31	2.45
High GDP	1.8	3.9	5.66	6	6.46	6.62	6.62	6.62	6.62	4.9
Low GDP	0	0	0	0	0	0	0	0	0	0
Base Connections	2	2	1	1	1	1				
High Connections	3	3	2	2	2	2				
Low Connections	1	1	0	0	0	0				
I/C Gas Demand										
Base I/C – GWh/y	12.93	13.27	13.52	13.79	13.98	14.18	14.42	14.67	14.92	15.08
High I/C – GWh/y	13.11	13.68	14.24	14.83	15.36	15.92	16.63	17.38	18.17	18.75
Low I/C – GWh/y	12.75	12.85	12.82	12.78	12.65	12.52	12.39	12.25	12.12	11.99
% Change I/C Sector										
Base to High	1%	3%	5%	7%	10%	12%	15%	19%	22%	24%
Base to Low	-1%	-3%	-5%	-7%	-10%	-12%	-14%	-16%	-19%	-21%
% Change Total ROI Gas Demand										
Total ROI to High	0.3%	0.8%	1.3%	1.8%	2.4%	2.9%	3.6%	4.3%	5.2%	5.7%
Total ROI to Low	-0.3%	-0.8%	-1.3%	-1.7%	-2.3%	-2.8%	-3.3%	-3.8%	-4.4%	-4.8%

The results of the analysis show that a significant variation in the assumptions regarding GDP have a reduced impact on I/C sector gas demand. The impact on I/C sector gas demand is seen to be relatively insignificant when viewed in the context of the total ROI gas demand.

4.5.2 Residential Connection Numbers Sensitivity

The residential gas demand is forecast by estimating the future rate of additional residential connections and associated gas demand per unit. This additional load is added to the most recent actual annual residential gas demand figures. An allowance is also made for future disconnections and energy efficiency savings.

A sensitivity analysis around the impact of alternative residential connection number forecasts was carried out in order to examine the effect of alternative assumptions. A high and a low annual connection number was assumed. The high scenario assumed double the number of new connections identified in the base case while the low scenario assumed no new connections. Both the high and low scenarios maintained the same level of disconnections assumed in the base case scenario. The results of the analysis are presented in Table 4.9.

The results of the analysis indicate that even a significant alteration in the assumptions regarding new connection numbers has only a minor impact on residential gas demand and has a negligible impact on the overall gas demand forecast.

4.5.3 Sensitivity Analysis for Power Generation Sector

The power generation gas demand forecast incorporates a significant range of input assumptions, e.g. electricity demand, forward fuel and carbon prices (see section 4.4.1). Applying a high/low variation to each of these assumptions would result in a large set of results, which would be very onerous to report on, compared to that of the I/C and Residential sector sensitivities. Consequently, a simplified sensitivity analysis for the power generation sector would not be sufficiently robust to provide a conclusive indication of the impact of variations to the input assumptions.

Table 4.9: Residential Connections Numbers Sensitivity

	2011 /12	2012 /13	2013 /14	2014 /15	2015 /16	2016 /17	2017 /18	2018 /19	2019 /20	2020 /21
Base Numbers	4,830	5,033	5,403	7,218	7,781	7,781	7,781	8,617	9,035	9,452
High Numbers	10,780	11,233	12,053	16,043	17,281	17,281	17,281	19,117	20,035	20,952
Low Numbers	-1,120	-1,167	-1,247	-1,607	-1,719	-1,719	-1,719	-1,883	-1,965	-2,048
Residential Gas Demand										
Base Res – GWh/y	8.30	8.25	8.19	8.14	8.08	8.03	7.97	7.92	7.87	7.82
High Res– GWh/y	8.31	8.29	8.26	8.22	8.20	8.17	8.14	8.11	8.08	8.06
Low Res – GWh/y	8.29	8.21	8.13	8.05	7.97	7.89	7.81	7.73	7.65	7.58
% Change Residential Sector										
Base to High	0.0%	0.0%	1.0%	1.0%	1.0%	2.0%	2.0%	2.0%	3.0%	3.0%
Base to Low	0.0%	0.0%	-1.0%	-1.0%	-1.0%	-2.0%	-2.0%	-2.0%	-3.0%	-3.0%
% Change Total ROI Gas Demand										
Total ROI to High	0.0%	0.1%	0.1%	0.2%	0.2%	0.2%	0.3%	0.3%	0.3%	0.4%
Total ROI to Low	0.0%	-0.1%	-0.1%	-0.2%	-0.2%	-0.2%	-0.3%	-0.3%	-0.3%	-0.4%

5. Gas Supply Outlook

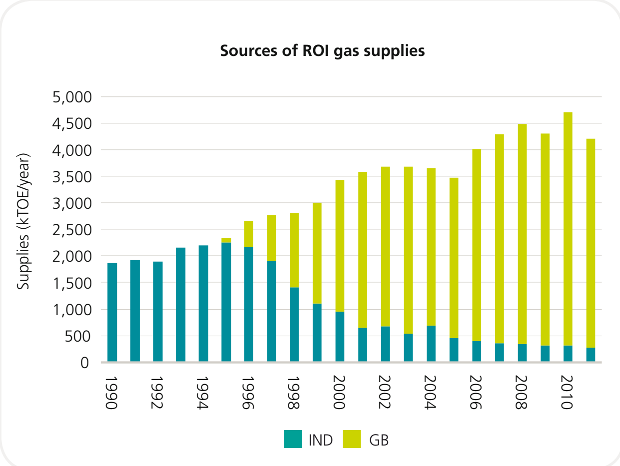
5.1 Historical Gas Supplies

The Moffat Entry Point continues to dominate both the annual and peak day gas supplies for the ROI and the BGÉ system as a whole.

The Moffat Entry Point accounted for 93% of annual ROI gas supplies in 2010/11 and 95% of BGÉ system supplies. Figure 5.1 reflects a growth in the 2010 annual gas supply followed by a reduction in 2011. The increase in 2010 is due in part to a number of severe weather events occurring in January and December 2010. Annual gas supply through the Moffat Entry Point had grown by an annual average of 1.1% over the period 2006/07 to 2010/11 but is estimated to decline in 2011/12 . Annual indigenous supply has seen a -4.8% annual average fall since 2006/07. It is to be noted that indigenous production includes the withdrawal of gas from storage facilities. It is estimated that almost 40% of gas labelled as indigenous supply in 2010/11 was gas withdrawn from storage facilities.

Moffat gas accounted for 89% of 2011/12 BGÉ system peak day gas supplies and 85% of ROI peak day supplies, as presented in Table 5.1. Peak day gas supply through the Moffat Entry Point has fallen by -15.9% on 2010/11 figures in line with a reduction in the peak day demand. Indigenous peak day production has also fallen by -5.0% from 2010/11 and by -6.0% annually from 2006/07 levels. The 2011/12 BGÉ system peak day gas supply fell by -14.8% from 2010/11 figures.

Fig.5.1: Historical Annual Indigenous Gas Production and GB Imports



5.2 Future Gas Supply Outlook

5.2.1 General Overview

In the short term the majority of the ROI gas demand will continue to be met from GB imports through the Moffat Entry Point. It is likely to change significantly from 2014/15 onwards, with a number of new gas supply projects at various stages of completion:

- The Corrib gas field off the Mayo coast is expected to commence commissioning in October 2014 for a period of up to 6 months followed by full commercial operation;

Table 5.1: Historical Peak Day and Annual Supplies through Moffat and Inch[1]

	2006/07 (GWh)	2007/08 (GWh)	2008/09 (GWh)	2009/10 (GWh)	2010/11 (GWh)	2011/12[3] (GWh)
Peak day						
Moffat[2]	234.5	245.6	251.4	292.5	303.9	255.7
Inch	43.6	40.0	35.6	34.8	33.7	32.0
Total	278.1	285.6	287.0	327.3	337.6	287.7
Annual						
Moffat[2]	69,236	72,645	70,446	73,843	72,320	63,827
Inch	4,976	4,772	4,259	4,128	3,765	3,895
Total	74,212	77,417	74,705	77,971	76,085	67,722

[1]Daily supply data taken from Gas Transportation Management System (GTMS)
[2]Table shows total Moffat supplies including supplies to ROI, NI and IOM
[3] Annual figures are forecast based on year to date values

- Shannon LNG has indicated 2017 as the earliest potential date for commercial operation of the proposed LNG terminal on the river Shannon, near Ballylongford in Co. Kerry;
- Islandmagee Storage and North East Storage continue to progress feasibility studies regarding the two separate salt-cavity storage projects near Larne in NI; and
- PSE Kinsale Energy have presented two possible future operational scenarios with activities either ceasing in 2017 or continuing throughout the NDS forecast period.

5.2.2 Low Flow Through Moffat

In order to investigate the impact of new indigenous supply sources on minimum flows through the Moffat Entry Point, it is necessary to examine the flows on a 'Summer Minimum Day'. Two significant events will lead to a reduction in the gas supply through the Moffat Entry Point, namely the operation of Kinsale Storage 365 days a year during the blowdown period (should KEL proceed with decommissioning) and the commissioning of the Corrib gas field. Please see section 6.2.3.8 for further detail.

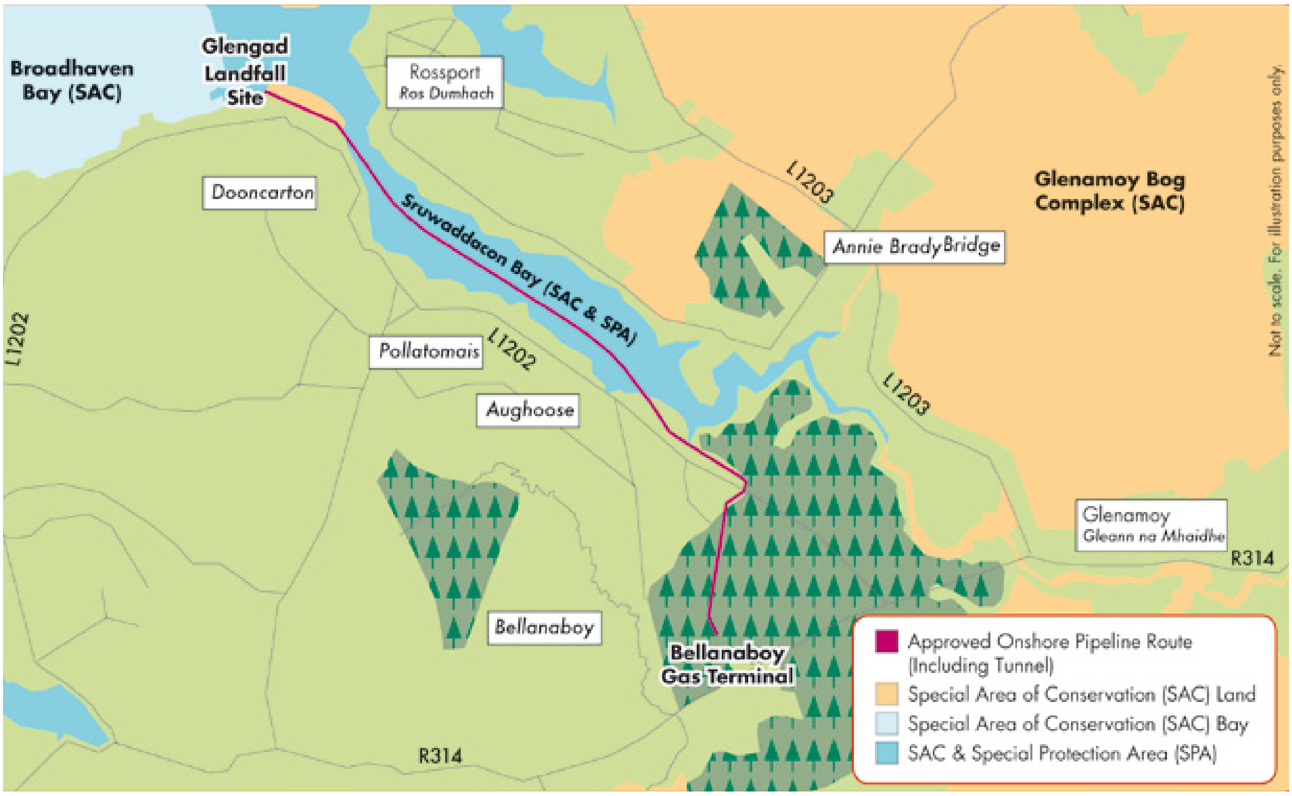
5.2.3 Corrib Gas

The Corrib gas field, located 83km off the coast of Mayo, is anticipated to be the main source of future indigenously produced gas. The project's final stage involves the construction of a 9km pipeline between land fall at Glenagad and the gas processing terminal at Bellanaboy, including the building of a 4.9km tunnel under Sruwaddacon Bay in North Mayo.

Table 5.2: Corrib Forecast Maximum Daily Supply

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

Fig.5.2: Glenagad (Landfall) to Bellanaboy Terminal Pipeline Route



Source: Shell E&P Ireland Ltd

5. Gas Supply Outlook

Based on the current construction and commissioning schedule, the Corrib field operators have indicated that commissioning of Corrib gas should take place in October 2014 for a period of approximately 6 months followed by full commercial operation.

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 5.2, is a revision from the previous figure of 10 mscm/d for the first three years.

For planning purposes, the NDS forecast assumes that the facility may not be operational during the peak winter period of 2014/15 which may occur during the facilities commissioning period and hence assumes first commercial production from October 2015. The impact of a 1 year sensitivity is also assessed where the facility is assumed to commence full operation in October 2014 or is delayed until October 2016.

5.2.4 Shannon LNG

Shannon LNG have indicated the earliest potential start date of 2017 for commercial operation. 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. It is 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).

Owing to the uncertainty regarding a possible start date the facility has not been included in the base supply scenario. The facility is examined in the NDS modelling noting the future contribution of the facility to the security of gas supply in Ireland.

5.2.5 Larne Storage

There are currently two separate salt-cavity gas storage projects being proposed for the Larne area in NI, by Islandmagee Storage and North East Storage respectively. Both projects are looking into the commercial feasibility of developing gas storage in the salt-layers that run underneath the Larne area:

- Islandmagee Storage is a consortium of Infastrata plc and Mutual Energy 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
- North East Storage Project, a consortium of Bord Gáis Energy and Storengy (a GDF-Suez company), is looking to develop a 3,308 GWh (300 mscm) storage facility near Larne, with maximum withdrawal and injection rates of 165-221 GWh/d (15-20 mscm/d) and 66-88 GWh/d (6-8 mscm/d) respectively.

Fig 5.3: Bellanaboy Gas Terminal

Source: Shell E&P Ireland Ltd

Islandmagee submitted a full planning application to the NI authorities in March 2010 and has since entered into agreements with BP Gas Marketing Limited ("BPGM") regarding the appraisal of the facility. The agreement will fund the activities necessary to further develop the project, including the drilling of a test borehole. The Islandmagee storage developers have indicated 2017/18 as a possible start date for commercial operation.

North East Storage completed a exploratory borehole in early 2012. Although sizeable layers of salt were not encountered, samples of the geology were extracted during drilling and will be analysed and correlated with the seismic survey results taken in 2009. A decision on the next steps for the project will be taken when these results are known later in 2012.

5.2.6 Celtic Sea Gas Storage

The existing Kinsale storage facility is Ireland's first and only offshore gas storage facility, which was developed and is operated by PSE Kinsale Energy. It currently has a working volume of c. 230 mscm, with a maximum withdrawal and injection rate of 2.6 mscm/d and 1.7 mscm/d respectively. This storage facility connects to the BGÉ transmission system at Inch.

PSE Kinsale Energy has expressed its intention to increase its storage capacity of the South West Kinsale facility through the installation of a new compressor with an expected operational date of summer 2013. The new expanded storage facility would result in a total working volume of 280 mscm, increasing from 230 mscm presently, with a withdrawal rate of 2.6 mscm/d remaining unchanged and an injection rate increasing to 2.25 mscm/d, up from 1.7 mscm/d.

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 blowdown 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 throughout the NDS forecast period.

Fig 5.5: Kinsale Energy Gas Rig

Source: PSE Kinsale Energy

5.2.7 Other Supply Developments

Providence resources are currently investigating the development of a gas storage facility, Ulysses, in the Kish Bank Basin offshore from Dublin in the Celtic Sea. They have indicated that a number of scenarios have been developed which have an associated range in capacity, off-take export rates and capital expenditure.

Recently Providence Resources commenced flow testing on the Barryroe prospect, the results of which are expected shortly. Future development in this area will continue to be assessed.

San Leon Energy continue exploration operations off the West coast of Ireland, located in the Porcupine, Rockall and Slyne basins on the Atlantic margin. They expanded their operations into the Celtic Sea, through the acquisition of Island Oil and Gas during 2010.

New production techniques mean that "unconventional" gas can now be produced from shale, coal-bed methane and other "tight" formations, on a more commercially viable basis. Bord Gáis Networks and Gaslink welcome any new sources of gas supplies which are produced safely and in an environmentally friendly manner. Developments in this area continue to be reviewed for their potential impact on future gas supply scenarios.

There is currently no firm data regarding the projects listed above, therefore, they have been omitted in the NDS forecast. This situation will continue to be kept under review for future NDS publications.

6. Network Analysis

6.1 Overview of Network Analysis

As outlined in chapter 5, considerable uncertainty continues to surround the timing of certain proposed supply projects and the future of an existing supply source on the Island;

- PSE KEL has indicated that 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 decommissioning phase when Inch supply is expected to comprise of production and cushion gas and total cessation of Inch supply post 2016/17.
- Shannon LNG has indicated the earliest potential start date for commercial operation at their proposed LNG terminal is 2017.
- Both Larne Storage developers continue to progress feasibility studies regarding their respective salt cavity storage projects.

Currently the Corrib field is the only prospective new supply source in the medium term, with first commercial gas supplies expected in 2015. Corrib is anticipated to meet approximately 33% of the ROI's peak day gas demand in its first year of production. However it declines relatively quickly, meeting approximately 20% of the ROI's peak day gas demand in 2020/21 (year 5 of production).

The Moffat Entry Point (interconnector system) supplied 93% of ROI gas demand in 2010/11, a contribution four times that of Great Britain's (GB) largest Entry Point on the NG NTS, St. Fergus, which met 23%[1] of GB supply in 2010/11. The ROI will continue to depend on the Moffat Entry Point and Interconnector System to provide over 90% of its gas demand until Corrib commences production and is likely to revert to this level of dependency post Corrib. The Moffat Entry Point and Interconnector system may be required to meet 100% of ROI gas demand in the longer term, should Inch cease and no other future supply sources materialise.

Last year's NDS, JGCS and Winter Outlook noted the capacity limits of the Moffat Entry Point (Interconnector System) will be approached over the coming winters and will be reached in 2013/14, should forecasted peak demands occur. The demand and supply forecasts in this year's NDS indicate the same capacity constraint will occur, albeit one year later in 2014/15[2]. The ongoing presence of non-uniform flow profiles at the Moffat Entry Point increases the likelihood of reaching capacity limits before 2014/15.

Similar to previous years, the network analysis undertaken for this year's statement assessed the adequacy of the transmission network to transport a range of forecasted gas flows. However, this year's NDS examines Moffat Entry Point (Interconnector System) in much greater detail than previous statements and the factors which impact on its capacity.

A slightly different approach has been adopted in presenting the modelling results and conclusions for this year's NDS. This year's statement presents the network analysis for the onshore ROI transmission system and Interconnector system in two separate sections. Section 6.2.2 and 6.2.3 are representative of the central or base view. A 3rd section, 6.2.4, discusses the results of the analysis for the other potential supply sources (Shannon & Larne), should they proceed.

This year's statement also includes a section on strategic network reinforcement, section 6.3. This section addresses why such reinforcement should be undertaken to mitigate the impact of losing a section of the onshore network for a sustained period of time. Appendix 4 provides an overview of the transmission network modelling and key modelling assumptions included in the network analysis for the NDS.

6.2 Network Analysis Results

6.2.1 Overview

The results and conclusions detailed in sections 6.2.2 and 6.2.3 are subject to the base demand scenario and the supply scenario summarised in the Table 6.1, which indicates the availability of each source of supply over the forecast period. The analysis also considered the impact of Corrib supply commencing from winter 2014/15 and winter 2016/17.

It is important to note, the results and conclusions of the network analysis detailed in the following sections are subject to a set of assumed demand and supply conditions. Any departure from these demand and/or supply conditions may lead to a change in pressure profiles and possible violation of system pressure limits.

1 Supply contribution by Entry Point provided by National Grid
2 The change by 1 year can be primarily attributed to a change in assumption regarding the cessation of existing Inch storage operations. Last year's statements assumed 2012/13, whereas the current assumption is 2013/14.

Table 6.1: Summary of Base Scenario

	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21
Inch*										
Corrib										
Moffat										

*Existing Inch storage operations cease in 2013/14, followed by 3 years of decommissioning and total cessation after 2016/17.

6.2.2 ROI Onshore Transmission System

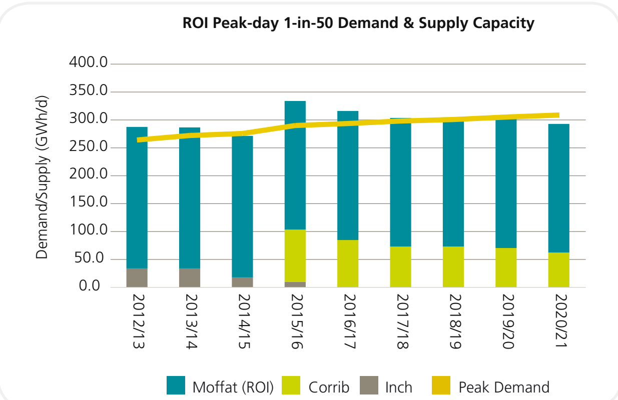
6.2.2.1 Winter Peak Days

The onshore ROI transmission system consists of the Ring-Main linking Dublin, Galway and Limerick. A number of spur transmission pipelines run from the Ring-Main to Cork, Limerick, Waterford, Dundalk and the Corrib Bellanaboy terminal in Mayo. The ROI transmission system also includes a compressor station at Midleton.

Network analysis was undertaken to determine if the ROI onshore transmission system has sufficient capacity to meet forecasted 1-in-50 peak day demands for the next 10 years. Corrib, Inch[3] and Moffat are the only sources of supply assumed in this analysis, due to the uncertainty associated with the other proposed supply sources. The 1-in-50 peak day ROI demand forecasts, assumed supplies and their associated supply capacities are illustrated in Figure 6.1.

Network analysis indicates that the ROI onshore system has sufficient capacity to meet all gas flow requirements up to and including 2017/18. Low pressures were observed in the Cork and Waterford areas of the network for all years from 2017/18, with minimum system pressure limits breached from 2018/19.

Figure 6.1: ROI Peak Day 1-in-50 Demands & Supply Capacity

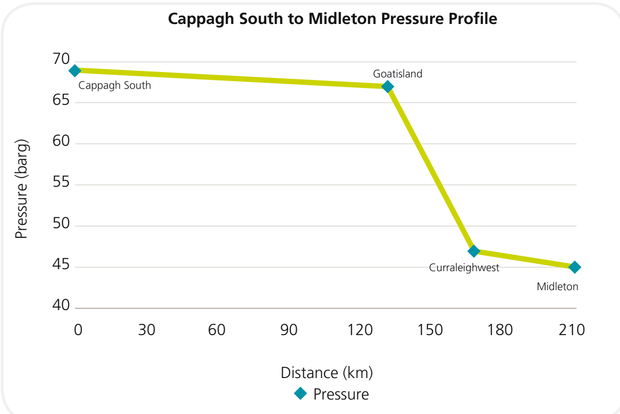


The absence of Inch supplies from 2017/18, results in all of the Cork and Waterford area demand being supplied from Corrib and/or the ICs (Gormanston & Loughshinny).

Corrib gas supplies travel south through the 30" Pipeline to the West (PTTW) to Goat Island (Co. Limerick), then through the 16" pipeline between Goatisland and Curraleigh West (GICWP) and finally through the twinned section of pipeline between Curraleigh West and Midleton.

Whilst the PTTW (upstream of Goat Island) and the Curraleigh West to Midleton pipelines have sufficient capacity to transport large volumes of gas, the 16" pipeline connecting Goatisland to Curraleigh West does not. As illustrated in Figure 6.2, this 37km pipeline experiences substantial pressure losses when subject to high flows.

Figure 6.2: Pipeline Pressure Losses - Cappagh South to Midleton



Similarly, the 180km Cork to Dublin (CDP) 18" pipeline between Brownsbarn and Curraleigh West experiences significant pressure losses when transporting large volumes of gas. Consequently, the pressure losses which occur in the CDP and GICWP result in low pressures downstream in both Cork and Waterford, resulting in minimum pressure limits being violated from 2018/19.

3 Inch supply is assumed to cease post 2016/17

6. Network Analysis

Figure 6.3: Cork Area Demand & Local Pressures

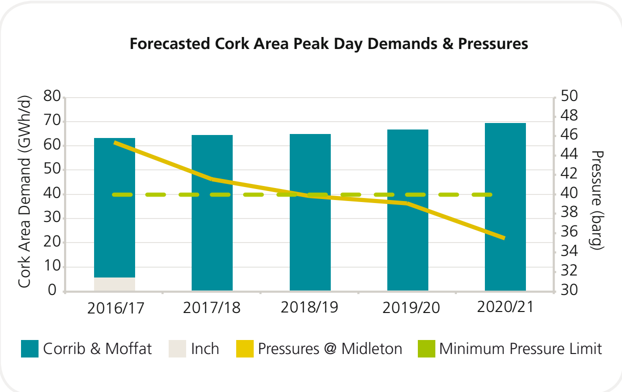


Figure 6.3 illustrates Cork area demand (the columns), the associated supplies that meet this demand and the local pressures[4].

Considering the timeline associated with the occurrence of such minimum pressure violations, i.e. approximately six to seven years away, and the future uncertainty regarding Celtic Sea operations, future statements will continue to monitor this situation and recommend appropriate action if and when it is required. It should be noted that the Goatisland to Curraleigh West pipeline reinforcement was identified in the Gas 2025 study, which was undertaken by the Department of Public Enterprise and BGÉ in the late 1990's.

6.2.2.2 Summer Minimum Days

The NDS demand and supply forecast indicates there maybe a number of days during the summer period in certain years when indigenous ROI supply capacity will be sufficient in meeting all of the ROI demand. Consequently there may be no gas supply required from the IC system on such days (subject to contractual arrangements between the Shippers and Suppliers/Producers).

Currently pressures in the ROI onshore transmission system remain relatively steady throughout the day, as they are primarily regulated/controlled by Gormanston AGI, with the subsea IC system absorbing the within day pressure swings that result from the within day demand diurnal.

However, if there was no gas supply required from the IC system (and through Gormanston), the pressure in the onshore ROI transmission system would be subject to;

- The flow profile from the indigenous supply sources, Corrib and/or Inch; and
- The within day demand diurnal.

The supply flow profile from Inch and Corrib is assumed to be flat. A flat flow supply profile combined with a within day demand diurnal would result in the within day pressure swings occurring in the onshore ROI transmission system.

Network analysis indicates all pressure and flow requirements may be met with supplies from Corrib and Inch alone on a 'Summer Minimum Day', i.e. the 'Summer Minimum Day' demand diurnal swing may be accommodated within the Ring-Main, assuming appropriate supply pressures and flow profiles.

6.2.2.3 Local Reinforcement

Notwithstanding the results and conclusions detailed in the previous sections, local system reinforcement could be required if large new connections (which are not anticipated in the demand forecasts) were to materialise.

6.2.2.4 Conclusion

Network analysis indicates the ROI onshore transmission system has sufficient capacity to meet the gas flow requirements on winter peak days and summer minimum days for the next six to seven years.

Though pressure violations were observed in the southern part of the transmission system (Cork and Waterford) for the 1-in-50 peak days in the later years of the forecast period, the occurrence of such low pressures were subject to the unavailability of Inch supply. Future statements will continue to monitor this potential issue, and recommend appropriate action if and when required.

6.2.3 Moffat Entry Point

6.2.3.1 Overview

GB gas imports will continue to meet the significant majority (or possibly all)[5] of the Island's peak day gas demand until Corrib commences commercial production. However, there is a limitation to the amount of GB gas that can meet the Island's demand, despite sufficient gas supplies being available in GB. This limitation is due to the technical capacity of the Moffat Entry Point on the BGÉ system.

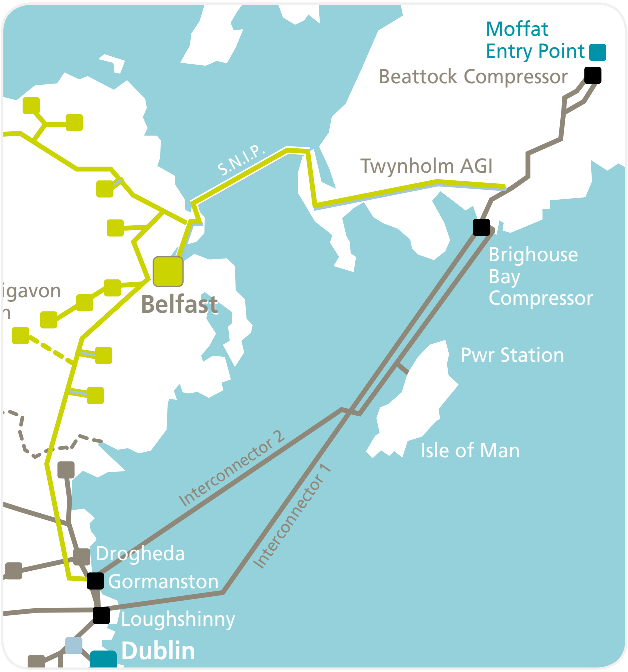
4 Pressure north of Midleton, Co. Cork
5 Moffat will be required to meet 100% of the Island's demand, if Inch supply is unavailable

6.2.3.2 Moffat Entry Point Technical Capacity

Technical capacity is defined as "the maximum firm capacity that the Transmission System Operator can offer to the network users, taking account of system integrity and the operational requirements of the transmission network"[6].

In simple terms, Entry Point technical capacity is a measure of the amount of gas that can be transported physically from a supply point in the gas network. The technical capacity of the Moffat Entry Point is determined by the technical capacity of the infrastructure between Moffat and the ROI onshore transmission system, known as the 'Interconnector system', comprising of the 'Southwest Scotland Onshore System' (SWSOS), i.e. Beattock compressor station, the onshore Scotland transmission system and Brighouse Bay compressor station, and the 'Subsea Interconnector system' (ICs) i.e. Interconnector 1 (IC1), Interconnector 2 (IC2) and the pressure reduction stations at Gormanston and Loughshinny (see Figure 6.4).

Figure 6.4: Overview of the Interconnector System



The potential technical capacity of the ICs is 51 mscmd[7] (subject to upstream infrastructure and pressures), however the current capacity of the SWSOS is 31 mscmd, thus limiting the capacity of 'Interconnector system' to 31 mscmd. Therefore, the current capacity of the Moffat Entry Point is limited to the the capacity of the SWSOS, 31 mscmd[8].

However, this technical capacity is only applicable for current year and following three years, and may reduce to 29 mscmd from 2015/16 for reasons outlined in the following section.

6.2.3.3 Future Technical Capacity of the Moffat Entry Point

One of the primary determinants of the capacity at the Moffat Entry Point is the pressures available from the National Grid NTS at Moffat (see section 6.2.3.7). The current technical capacity of 31 mscmd is based on an Anticipated Normal Offtake Pressure (ANOP) pressure of 47 barg. However, actual pressures approaching 45 barg have been observed on various occasions over the past 20 months. National Grid is contractually required to provide gas at a minimum pressure of 42.5 barg (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.

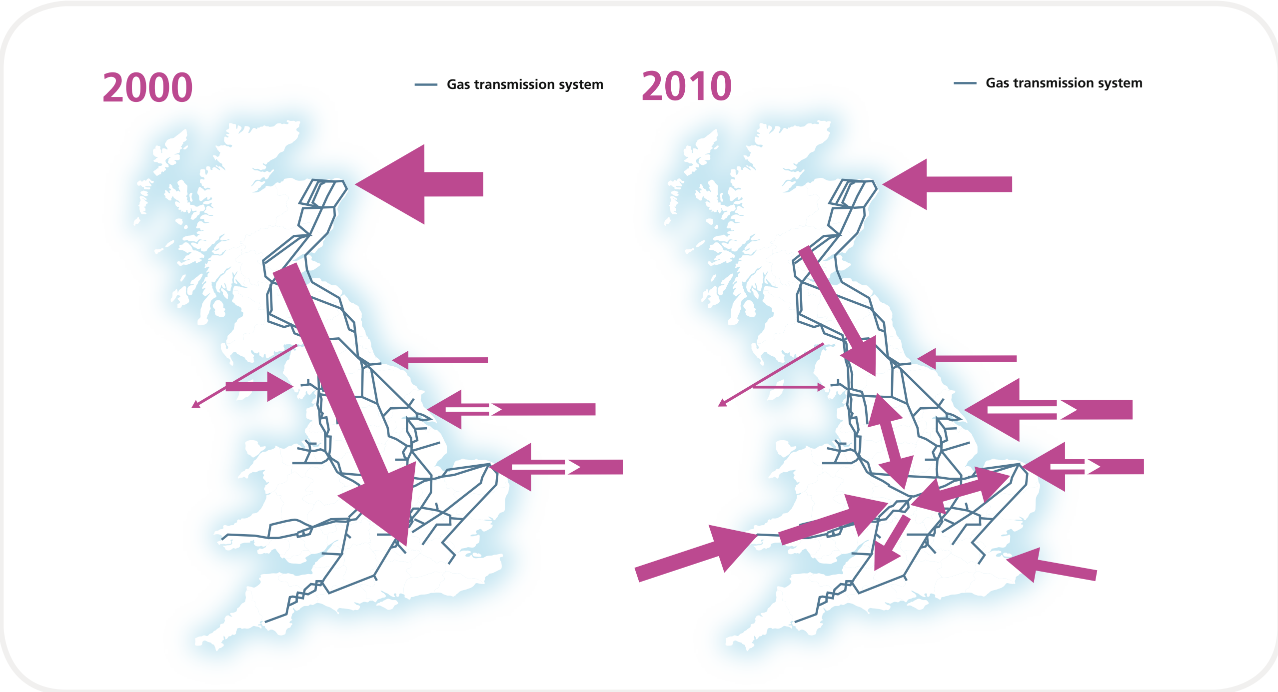
Gaslink and Bord Gáis Networks are engaged with National Grid regarding the NTS pressures at Moffat. National Grid recently indicated that the occurrence of pressures below the 47 barg are isolated 'within day' incidents, and that it is prudent to continue assuming the ANOP pressure of 47 barg for the current year and following 3 years, for Network Planning purposes.

National Grid have also advised that the Moffat Exit Point is now classified as a 'Null Point' from a network analysis point of view on the GB NTS, due to the change in GB flow patterns. As illustrated in Figure 6.5, 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.

6 European Regulation EC 715/2009
7 Based on the nominal design capacity of IC1 (17mscmd) and IC2 (34 mscmd)
8 The technical capacity of the Moffat Entry Point was revised in October 2011, in response to a change in assumption regarding the mode of operation at Beattock compressor station. Further compressor modelling studies have indicated Beattock Compressor Station is limited to operating in 'Parallel' mode in order to accommodate the range of within days flows associated with 'Renominations' at the Moffat Entry Point. The previous technical capacity, 32 mscmd, was based on the station operating in series mode, with a discharge pressure of 85 barg. Further details on Moffat Entry Point Technical Capacity; http://www.gaslink.ie/index.jsp?p=136&n=205.

6. Network Analysis

Figure 6.5: GB NTS Gas Supply Patterns 2000 and 2010



Source: National Grid (UK)

This change in supply pattern is expected to continue as UKCS flows through St. Fergus continue to decline. Gas supplies will have to be routed from the 'south to the north', despite the NTS been historically designed to flow gas in the opposite direction, i.e. 'north to south'. NG have stated in their 'Gas Ten Year Statement 2011' that they are "approaching a point where, without additional network capability to deliver 'south to north' flows, we (NG) will not be able to meet our 1-in 20-demand obligations in Scotland". This could have negative implications for pressures at Moffat.

In response to discussions with National Grid, Bord Gáis Networks will assume 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 a pressure of 45 barg at the Moffat Exit Point on the GB NTS. Consequently, the capacity of the Moffat Entry point will reduce from 31 mscmd to 29 mscmd for all years from 2015/16 (inclusive).

6.2.3.4 Twynholm Exit Point

Under existing arrangements, NI is entitled to 8.08 mscmd of Exit Capacity at the Twynholm Exit Point on the BGÉ UK transmission system (i.e. SWSOS). However, it is important to note that the Twynholm Exit Capacity does not necessarily imply the NI network downstream of Twynholm has the capacity to transport 8.08 mscmd of gas to consumers in NI[9].

The network analysis undertaken for determining the technical capacity of the Moffat Entry Point indicated that the pressure at Tywnholm was marginally above 56 barg at this Exit Point. The forecasted Moffat flows for the forthcoming winters are expected to approach the capacity limits of the Moffat Entry Point. On this basis, and considering the stepped/swing profiled flows at Moffat, Bord Gáis Networks advises that prevailing pressures in excess of 56 barg should not be assumed at Twynholm for NI network planning purposes.

The NI system is outside the scope of the NDS, and, therefore was not analysed. However, based on the results of the network analysis published in previous NI Pressure Reports, Bord Gáis Networks understand the

9 Moffat is a similar example to that of Twynholm; Moffat Exit Point Capacity on the GB NTS, 39 mscmd, is greater than the Moffat Entry Point Capacity on the BGÉ UK system, 31 mscmd. BGÉ declare the technical capacity of the Moffat Entry Point, 31 mscmd, based on an analysis of their own transmission system downstream of Moffat (as per the requirements of EC 715/2009).

technical capacity of the SNIP could be of the order of 6 mscmd, assuming 56 barg at Twynholm (upstream at the AGI). It should be noted, the scenarios in this year's NDS have not considered gas supplies to Northern Ireland via the Gormanston Exit Point. This assumption will continue to be kept under review for future NDS publications.

6.2.3.5 System Flexibility and Flow Profiling

Ideally 'day ahead' gas demand nominations at the Moffat Entry Point would remain unchanged and there would be no requirement for 'Renominations', allowing the Transmission System Operator to flow the gas with a uniform flow profile[10], i.e. flat flow profile.

The reality, however, is very different with 'Renominations' occurring hour to hour during the gas day, in response to changes in the downstream customer gas demand or market dynamics. This requires the system operator 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).

'Renominations' at the Moffat Entry Point are inevitable, as it is impossible to consistently predict 'day ahead' gas demand with 100% accuracy. This is particularly relevant to the power generation sector, which accounts for approximately 60% of peak day demand. Hourly changes or fluctuations to power generation gas demand can occur for a number of reasons, e.g. higher than anticipated electricity demand or lower than anticipated wind levels could potentially result in additional gas fired station(s) being dispatched. To date, the gas network has provided the required flexibility to the Single Electricity Market (SEM).

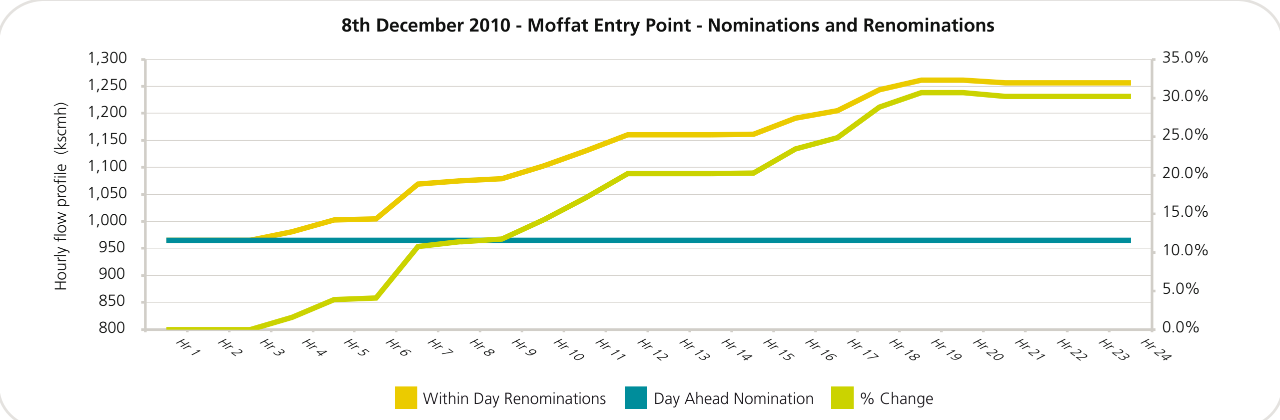
Such events can significantly impact on the scale of 'Renominations' at the Moffat Entry Point, e.g. if a 85 MW OCGT was dispatched unexpectedly, its total maximum gas demand for the day would be equivalent to the peak day gas demand of approximately 60,000 residential homes.

Figure 6.6 illustrates the level of variation between the original 'day ahead' nominations and the actual 'within day' 'Renominations' observed on the 8th of December, during the severe weather period in 2010. As illustrated, there was a variation of +20%, increasing to +30% for a significant number of hours during the gas day. This pattern is not unique to the 8th of December, as renominations are typical on most days.
Such a scale of 'Renominations' could not be accommodated for the 1-in-50 peak day demand forecasts over the forthcoming winters.

6.2.3.6 Moffat Entry Point Peak Day Supply Outlook

Table 6.2 illustrates the forecasted 1-in-50 peak day flows through the Moffat Entry Point (Interconnector system) for the current year and following 9 years, the current capacity of the Moffat Entry Point (Interconnector system) and the percentage of capacity utilised (assuming a flat flow profile).

Figure 6.6:'Day Ahead' Nominations and 'Within Day' 'Renominations' on the 8th December 2010



10 Technical capacity of Moffat Entry Point is subject to the system being in a steady state, i.e. a uniform flow profile

6. Network Analysis

The forecasted flows in Table 6.2 demonstrate that capacity limits of the Moffat Entry Point (Interconnector system) are being approached on the 1-in-50 peak days for the forthcoming winters. The residual of '% of Capacity utilised' is an indication of the amount of physical flexibility available to accommodate renominations.

All shippers were advised last winter and will continue to be advised in advance of the forthcoming winters, to flatten flow profiles in the SWSOS, i.e. provide timely and accurate nominations and renominations. This will assist in mitigating the risk of a supply interruption at the Moffat Entry Point over the next two winters.

However, by 2013/14 there is little or no flexibility to accommodate any Shipper 'Renominations' at the Moffat Entry Point. Capacity limits will be reached in 2014/15 and any subsequent years Corrib is delayed, regardless of how the gas flow is profiled. Consequently a demand side response would be required. This situation will arise again in 2018/19, assuming no new supply sources materialise and Inch supplies have ceased.

The continuation of existing Celtic Sea storage operations post 2013/14 would reduce the forecasted flow requirement at Moffat. Consequently, capacity limits would not be reached, but would be approached in 2014/15 and 2020/21, with little or no system flexibility to accommodate any change to 'day ahead' nominations, i.e. no renominations. It should also be noted, supplies from the Celtic Sea through the Inch Entry point are subject to a number of factors including;

- Commercial/contractual arrangements between the facility operator's (Kinsale Energy) and the relevant shippers;
- The time of year. If a severe weather period occurred in the latter part of the winter, the required gas stocks and/or the delivery(withdrawal)[11] rate may not be available.

In addition to this, an outage at (or upstream) of Midleton compressor station, could result in the requirement for Moffat (Interconnector system) supply to meet all of the Island's demand.

6.2.3.7 Current Limitations of the Moffat Entry Point

The capacity of the Moffat Entry Point is limited by the technical capacity of the SWSOS, which is currently subject to the technical capacity of Beattock compressor station (and the associated downstream pipeline). The technical capacity of Beattock compressor station is determined by a number of factors, primarily;

- The design of the compression facility; and
- The station's inlet pressure; and
- The station's discharge pressure.

The capacity of the station increases[12] if higher inlet pressures are available, discharge pressures are reduced and/or the power delivered within the the compressor station is increased.

Table 6.2: Moffat Capacity, Moffat Peak Flow Forecast and Moffat Capacity Utilised

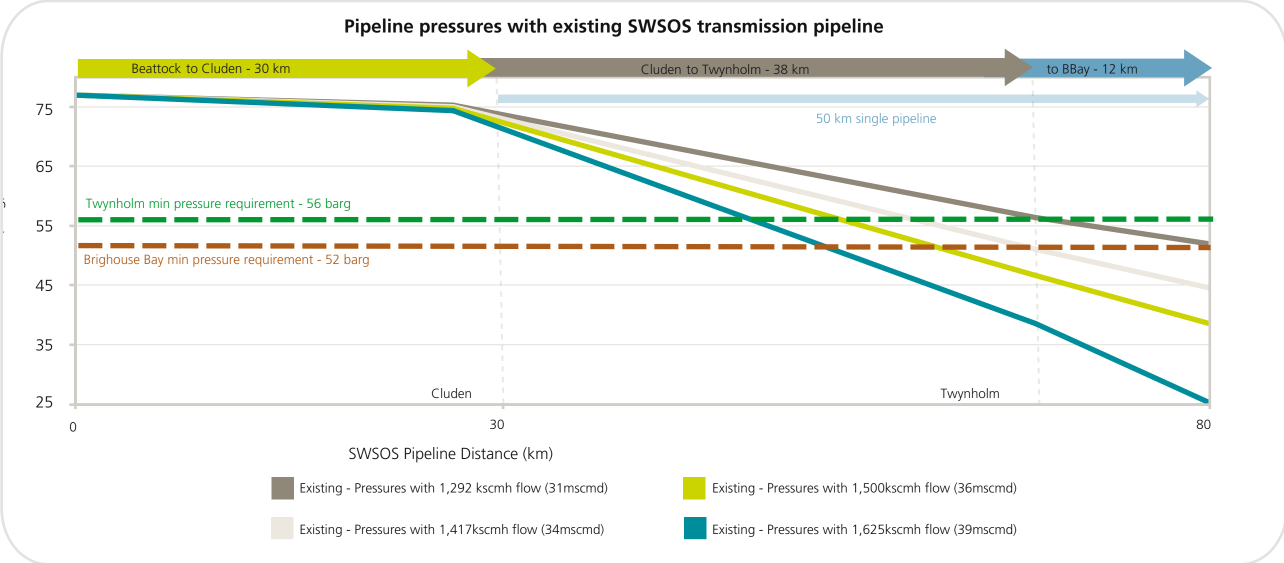
Year	Moffat Capacity[1] (mscmd)	Forecast Peak Flow (mscmd)	% of Capacity utilised (Flat Flow)[2]
2011/12	31	30.5	98.4%
2012/13	31	29.4	94.8%
2013/14	31	30.1	97.1%
2014/15	31	31.8	102.6%
2015/16	29	25.8	89.0%
2016/17	29	26.8	92.4%
2017/18	29	28.9	99.7%
2018/19	29	29.2	100.7%
2019/20	29	29.9	103.1%
2020/21	29	31.1	107.2%

[1]Details on the Technical Capacity; http://www.gaslink.ie/index.jsp?p=136&n=205.

[2]If Corrib is delayed one year, Moffat flow for 2015/16 will increase to 33.6 msmcd with 108.4% of capacity utilised

11 Delivery/Withdrawal rate is a function (in part) of the volume of gas in storage. Higher delivery/withdrawal rates can be achieved when storage is full to max capacity.
12 This increase is theoretical and refers specifically to the compressor units. Further analysis and physical testing of the station's subsystems may be required to verify an increase to overall station capacity.

Fig 6.7: Existing SWSOS Transmission System Pressures for a Range of Flows



The power available within the compressor station is limited by the existing technology in the station and it is likely station reinforcement (including new compressor and turbine technology) would be required to increase this power.

Inlet pressures are subject to the pressures available from the National Grid (NG) National Transmission System (NTS) at Moffat, and therefore, are outside the control of Bord Gáis Networks (subject to existing contractual arrangements)[13].

The discharge pressure at Beattock is within the control of Bord Gáis Networks, and therefore (in theory), could be reduced to increase flow through the compressor station, thus increasing the capacity of the Moffat Entry Point. However, there are limitations to reducing the discharge pressure at Beattock.

Beattock is required to provide sufficient pressures to meet the downstream pressure requirements at Twynholm[14] and Brighouse Bay compressor station[15]. A significant amount of pressure is lost between Beattock, Twynholm and Brighouse Bay, particularly during periods of high demand due to the single pipeline. Figure 6.7 graph illustrates the pressure losses across 80 km SWSOS for a range of flows, with a pressure losses ranging from ~27.0 barg to ~49.0 barg for flows of 1,292 kscmh (31 mscmd) and 1,625 kscmh (39 mscmd) respectively.

As illustrated, the majority of the pressure losses occur in the 50 km single 24” pipeline between Cluden, Twynholm and Brighouse Bay, and increase as the volume of flows increase. Such pressure losses in the SWSOS place an additional obligation on Beattock compressor station. Beattock is required to discharge at a pressure to meet downstream pressure requirements at Twynholm and Brighouse Bay, but implicit in this, is the requirement to provide pressure to compensate for the significant pressure losses in the SWSOS.

In effect, the discharge pressure at Beattock is constrained by a requirement to compensate for the pressure losses in the SWSOS. Removing this constraint would allow Beattock to discharge at lower pressures, thus increasing the capacity of the compressor station and consequently the Moffat Entry Point (Interconnector system).

It is also important to note; increasing the capacity of Beattock compressor station does not strictly mean an increase in capacity of the Moffat Entry Point (Interconnector system). As noted above, the

13 Minimum pressure of 42.5 barg for flows up to 26 mscmd under the Pressure Maintenance Agreement (PMA)
14 ‘Transportation Agreement makes provision for reserved capacity of up to 8.08 mscmd at 56 barg.
15 Minimum design inlet pressure of 52 barg, however, pressures in excess of 60 barg would be required during periods of peak demand.

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constraining factor is the single 50km section of SWSOS pipeline. An increase to the station inlet pressures and/or an increase in compressor power will increase the capacity of the station. However, while Beattock may have the capacity to flow higher volumes of gas, the SWSOS transmission system will not necessarily have the capacity to transport the gas downstream to Twynholm and Brighouse Bay.

6.2.3.8 Moffat Entry Point Minimum Flows

In addition to a maximum capacity limit at the Moffat Entry Point, there is also a minimum flow limit associated with the Moffat Entry Point. Currently, this minimum flow limit is determined by the minimum design flow criteria of Beattock Compressor Station, 500 kscmh (12.0 mscmd).The fall off in gas demand on certain days (as a result of increasing wind generation capacity) combined with Corrib supply coming onstream and the Inch Entry supplying 365 days[16], will result in the reduction of flows through the Moffat Entry Point. This is demonstrated in the summer minimum day forecasts for certain years (see section 6.2.2.2), when Moffat supplies will be only required to meet NI and IOM demand.

Notwithstanding the engineering works that were completed at Beattock Compressor Station in 2011[17], the operating envelope of the station is limited by the station's compressor/turbine technology and the station's subsystems. Facilitating flows that exceed minimum or maximum design flow limits would be subject to actual testing. It may not be possible for Beattock compressor station to facilitate the low flows referred to above and additional investment at the station may be required, in order to do so.

6.2.3.9 Moffat Entry Point - Virtual Reverse Flow and SEM Intraday Trading

Gaslink developed a Virtual Reverse Flow (VRF) product at the Moffat Entry Point in 2011. Physically the flow remains unidirectional but through virtual reverse flow, contractual reverse flow of the gas is possible. Currently, it is unknown how the VRF will impact the 'within day' flows/profiles nominations at Moffat and consequently operations at Beattock.

The Single Electricity Market (SEM), is due to change with the introduction of Intraday trading arrangements in July 2012. This could potentially impact the commercial behaviour of the generators who participate in the SEM. Considering the high level of gas fired generation in the SEM, such change may impact (power generation) shipper behaviour (renominations) and the resultant operation of the network, especially at the Moffat Entry Point.

The impact (if any) of both the VRF and SEM Intraday Trading will be continually monitored and assessed. Future development statements (and/or Winter Outlook documents) will address any issues, that may arise as a consequence of either or both of these two market developments.

6.2.4 Future New Supply Sources

The development of any new supply sources on the Island of Ireland would enhance Ireland's security of supply and reduce the high level of dependency on Moffat.

As noted in section 6.1, considerable uncertainty surrounds the timing of the various proposed supply projects. While none of these proposed supply projects have been included in the central/base view, they have been considered in a sensitivity analysis.

As noted in previous development statements, there is a limitation to the amount of gas that can be physically transported from the west coast to the east and/or south coast while maintaining pressures within maximum and minimum operating system pressure limits, on peak days. The network analysis undertaken for this statement indicates this limit is relatively unchanged from previous years, i.e. approximately 18.5 mscmd (assuming no Inch supplies), reducing to 17 mscmd (assuming Inch supplies). Increasing this limit would require network reinforcement.

An increase in supplies through the Inch Entry Point exceeding the current capacity of Midleton Compressor Station, 6 mscmd, would also require network reinforcement. In addition to upgrading the existing compression facilities at Midleton, there maybe a requirement to reinforce the transmission network between Inch and Midleton, and Goatisland to Curraleigh West.

16 PSE KEL have indicated, supplies through the Inch Point may be available all year round in the event decommissioning of existing storage operations proceeds.
17 A volume control system that will increase the operating envelope of the turbo compressor units in the station

As noted in previous development statements, the current configuration at Gormanston will only facilitate flows from IC2 to NI via the SNP. System modifications would be required at Gormanston to facilitate flows from NI to the ROI via the SNP, if either (or both) of the Larne projects were to proceed (and subject to the appropriate regulatory and commercial arrangements being in place to facilitate such flows). Further modifications may also be required to the infrastructure in NI and south-west Scotland, if there was a requirement to reverse flow Larne gas through the SNIP and IC system to ROI and/or GB.

6.3 Strategic Network Reinforcement & Future Analysis

The results and conclusions detailed in the previous sections of this chapter are reflective of the adequacy of the transmission network under normal operating conditions.

Network analysis undertaken for this statement and previous NDS publications have assessed the adequacy of the transmission network to meet forecasted flows, under the assumption that all parts of the transmission network are fully functioning and no network event has occurred, e.g. losing a section of the Ring-Main due to a pipeline breach.

Gaslink and Bord Gáis Networks, as prudent system operators and owners, believe strategic network reinforcement should be considered as part of the long term network development plan. Such reinforcement should be undertaken to mitigate the impact of losing a section of the onshore network for a period of time in excess of 5 days.[18]

Bord Gáis Networks's PR3 Capex submission included a proposal to reinforce the 37km transmission pipeline on the Ring-Main between Goatisland (Co. Limerick) and Curraleigh West (Co. Tipperary), in order to enhance the security of supply to the southern half of the network. The network analysis undertaken for this proposal considered the consequences of a breach to the Cork Dublin Pipeline (CDP), which would result in loss of service through this section of pipeline.

Should such an event occur and no gas supply is available from Inch, the PTTW and the existing Goatisland to Curraleigh West pipeline would be required to transport all of the gas to meet the Cork area and Waterford/ Wexford area gas demand.

The network analysis demonstrated that while the PTTW has sufficient capacity to transport large volumes of gas, the pipeline between Goatisland and Curraleigh West does not. This section of 37km 400mm diameter pipeline experiences substantial pressure losses when subject to high flows.

Considering the high level of electricity produced by gas fired plant, c. 55% (which is anticipated to continue increasing) and the significant portion of the gas fired plant portfolio in the southern part of the country (which is also expected to increase with Great Island CCGT), a gas supply interruption to the southern part of the network could have a detrimental impact on the national electricity grid and could result in a supply interruption.

A recent event on the southern section of the Ring-Main, demonstrated that the loss of service through a section of the 'Ring-Main is a reality. The 180km 450mm diameter transmission pipeline between Brownsbarn (Dublin) and Curraleigh West was required to transport all of the gas to gas consumers located in the southern part of the ROI network. The operation of the network proved to be very challenging during this period, particularly due to the limited capacity associated with this section of pipeline.

If such an event had occurred during a period of higher demand, particularly the winter peak period, it is certain a supply disruption to gas customers in the south would have occurred, specifically in the power generation sector.

The advent of Corrib and/or other new supply sources on the west coast will greatly enhance the ROI's security of supply position. Nevertheless, transporting large volumes of gas through relatively narrow sections of the network, i.e. the 37km 400mm diameter GICWP and 180km 450mm diameter CDP, will result in very significant pressure losses regardless of the upstream supply capacity.

18 Baseload gas fired plants are required to hold 5 days of secondary fuels stocks as a safeguard for security of electricity supply, in the event of a gas supply disruption. A gas supply disruption exceeding 5 days could result in an electricity supply disruption.

6. Network Analysis

In order to guarantee security of supply to all gas consumers located in the southern half of the country and consumers on the national electricity grid, the Goatisland to Curraleigh West pipeline should be a priority strategic reinforcement, in the short to medium term. Reinforcing the CDP (or sections of the CDP) may be required post 2021.

6.4 Conclusions

The ROI onshore transmission system has sufficient capacity to meet the gas flow requirements on winter peak days and summer minimum days for the next six to seven years. Though pressure violations were observed in the southern part of the transmission system (Cork and Waterford) for the 1-in-50 peak days in the later years of the forecast period, the occurrence of such low pressures were subject to the unavailability of Inch supply. Future statements will continue to monitor this potential issue, and recommend appropriate action if and when required.

The operation of the Interconnector system on low demand days will require further studies to determine the optimal solution(s) to resolve any of the commercial/regulatory implications (e.g. security of supply) which may arise, in addition to minimum flow constraints at Beattock Compressor Station.

Gas flows through the Moffat Entry Point are anticipated to approach capacity limits on peak days, with little or no system flexibility for renominations, in the short to medium term and in the longer term, unless new supply sources are developed on the island, regardless of existing Celtic Sea operations continuing post 2013/14.

Forecasted Moffat flows indicate the capacity limits of the Moffat Entry Point will be reached in 2014/15 and for any further years if Corrib is delayed, regardless of how the gas flows are profiled. The ongoing presence of non-uniform flow profiles at the Moffat Entry Point increases the likelihood of reaching capacity limits before 2014/15. Therefore, absent system enhancements a demand side response will be required. This situation will arise again in 2018/19, assuming no new supply sources materialise and Inch supplies have ceased.

The Island's Regulatory Authorities (RAs) undertook a consultation in November/December 2011 to determine the most appropriate/optimal mitigation measures to address this potential capacity constraint. The RAs have not yet indicated what mitigation measure would be favourable. Bord Gáis Networks and Gaslink indicated in their response to the consultation that reinforcing the 50 km single section of pipeline in south-west Scotland would be the most appropriate mitigation measure/solution. Bord Gáis Networks and Gaslink will continue to recommend this as the most appropriate measure/solution to resolve the capacity constraint and await instruction from the RA.

Reinforcing the 50 km single section of the SWSOS transmission system guarantees the supply capacity and security to meet the ROI's future demand requirements in the short, medium and long term.

Gaslink and Bord Gáis Networks, believe strategic network reinforcement should be considered as part of the long term network development plan. In order to guarantee security of supply to all gas consumers located in the southern half of the country and consumers on the national electricity grid, the Goat Island to Curraleigh West pipeline should be a priority strategic reinforcement in the short to medium term.

7. Networks Asset Management & Development

The safe and efficient operation of a gas network is dependent on the total network asset base performing to required levels, from the point of entry through to the point of delivery.

In order to safely and efficiently deliver gas to customers, as well as maintain a satisfactory level of system performance, the performance and care of those assets used in the transportation of gas through the BGÉ gas network is continually analysed and evaluated by the Asset Management function within Bord Gáis Networks. Asset Management also evaluates and proposes business cases where appreciable improvements to system performance, safety and/or reliability can be achieved through capital investment in the asset base.

For ease of management of these assets, Bord Gáis Networks has defined five asset categories:

- Compressor Stations
- AGIs & DRIs (Pressure Regulating Installations)
- Meters
- Communications & Instrumentation
- Pipelines

Each asset class has been assigned a dedicated "Asset Owner" who is responsible for optimising the performance of their asset class while ensuring a quality customer service is delivered safely in a cost efficient manner.

Asset Integrity is responsible for maintaining and maximising the integrity of all of the asset categories. Asset Integrity also ensures the quality of the natural gas which enters and passes through the BGÉ pipeline network is to a satisfactory standard in terms of its composition for delivery to customers while also monitoring levels of impurities within the gas.

Network Analysis & Strategic Planning, also within Asset Management, examines and analyses the long and short term capabilities and security of both the transmission and distribution networks, in the context of possible demand and supply scenarios.

Asset Management also houses other functions which are key to the optimal management of the Irish gas network, including;

- Asset Information Management
- Investment Management (Performance and Planning)
- Asset Programme Management
- Conceptual Planning
- Integrated Planning; and
- Contract Strategy.

7.1 Compressor Stations

7.1.1 Introduction

Compressor Stations are used in the high pressure transmission network to raise the pressure of the gas within the system and enable it to flow in adequate quantities to all parts of the network. Bord Gais Networks operates three compressor stations in its transmission network, two located in the UK and one in Cork.

These three stations are responsible for compressing 100% of Ireland, Northern Ireland and the Isle of Man's gas into the network making them among the most critical assets on the network. Due to the criticality of the compression facilities, several features have been integrated into the design of the plants to improve their reliability and maintain a secure supply of gas to the island of Ireland.

7.1.2 Basic Compressor Station Design

The compressor stations consist of three primary components

- Turbo Compressor Units
  - Gas Turbine Prime Mover
  - Centrifugal Compressor
  - Associated Pipework and Valves
  - Turbo Compressor Control System
- AGI
  - Station Filters
  - Metering Streams
  - Fuel Gas Treatment System
  - Station Valves

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- Site
    - Station Control Room containing
        - Station Control System, ESD and Fire & Gas Systems
        - Network SCADA Connection
    - Administration Offices
    - Workshop and Stores Facilities
    - Security Systems

All of the above components have been designed to remove any single point of failure from the plant, and Bord Gáis Networks continuously strive to further improve the reliability of the plants.

Figure 7.1: Compressor Station Turbine Halls

7.1.3 Turbo Compressor Units Reliability

The capacity of the compressor stations is designed around an estimated peak demand, similar to the rest of the network (typically the 1 in 50 winter model). Once the estimated peak demand is determined then a level of redundancy is added in, typically an extra unit is installed. The peak operating model for the compressor stations is then;

- Beattock: 4 Turbines, operating 3 units at peak loads
- Brighouse Bay: 6 Turbines operating 5 units at peak loads
- Midleton: 3 Turbines operating 2 units at peak loads

Due to the high operating speed and harsh operating conditions within the turbines, failure of a unit generally tends to be catastrophic, leading to either a replacement of the turbine core or a substantial part of the core.

This will leave the unit out of action for a considerable period of time possibly (1-6 months). If this were to occur during the peak operating period during the winter, then the compressor station would not be able to provide adequate compression to meet the demand of the network without the spare unit being available.

In order to further improve the security of supply of the compressor stations, the turbines are housed in separate turbine enclosures with independent fire detection and suppression systems. The turbine enclosures are housed in separate turbine buildings (typically two units per hall) as shown in figure 7.1.

7.1.4 Ancillary Systems

In the case of ancillary equipment on site, Bord Gáis Networks uses an active and standby arrangement of all primary components to ensure reliability. The sites essential ancillary systems include;

- Air systems
- Nitrogen generating systems
- Lub oil Systems
- Water and reverse osmosis processes
- Fuel gas measurement and treatment systems
- Station control, fire and gas and emergency shutdown systems

All of these systems operate on an active and standby arrangement to ensure that one unit or stream can be shut down for maintenance, whether planned or unplanned, without effecting the process or operation of the plant.

7.1.5 Electrical Power Systems

In the case of the electrical supply to site, all of the compressor stations are designed to operate in 'island' mode without an incoming supply. This is achieved by having all essential components on a UPS (Uninterrupted Power Supply) which will, in the event of a power failure, continue to supply all essential equipment from the stations backup battery banks while the emergency generator automatically starts up and connects to the main switch board. All of the compressor stations have an adequate diesel supply to run the emergency generator for a minimum period of a week.

7.1.6 Summary

Bord Gáis Networks goes to great lengths to ensure the security of the gas supply to Ireland. The ample level of redundancy built into the compression facilities has ensured that to date there has been no disruption in gas supplies caused by the failure of a compressor station component. Bord Gáis Networks will continue to work on improving the stations reliability in both existing plants and utilise the knowledge learned from this process to design further reliability into any future expansion of the compression facilities.

7.2 AGIs & DRIs

The network consists of a number of Above Ground Installation (AGI) assets, on the transmission system where the pressure of the gas in the system is regulated for delivery to transmission connected customers or supply into the lower pressure distribution network. Further pressure reduction occurs on the distribution system to supply high density locations such as those found within city and town centres. In these District Regulating Installations (DRIs) gas pressure is further reduced via regulating stream(s) to domestic inlet pressures.

The Industrial & Commercial installations (I/C) can operate from a medium pressure or low pressure network and are required to supply the required operating pressure to the industrial customer.

Last year a meter replacement program was initiated to replace I/C meters, 20 years or older, due to reliability and obsolesce. The replacement programme will address this by standardising on the design of the meters to conform to European norms making them compatible with meters from multiple vendors. This programme will enable quick and easy replacement of meters into the future and facilitate a care regime with meter refurbishment and calibrations at intervals recommended by policy and sampling.

Figure 7.2: AGI

Figure 7.3: I/C Installation

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As part of this meter replacement program an I/C installation refurbishment program was also initiated, this program is to improve the overall safely, reliability, appearance and provide good protection of the meter and pressure reduction components. It includes the rehabilitation of fire service valves and replacement of worn/faulty equipment.

These I/C Installations were designed and built to earlier standards, new standards are more stringent and must now be observed in light of the modifications done for meter replacement. It is also intended to calculate the required ventilation and identify the hazardous zone classification of the installation and also provide hazardous area drawings for each site in order to comply with the ATEX directive. This is a continuous improvement programme to ensure these installations continue to comply with the relevant legislation, technical standards and codes of practice.

7.3 Meters

7.3.1 Overview

Asset Management promotes a 'Whole of Life Strategy' across all Bord Gáis Networks meter assets while complying with all relevant safety, metrological accuracy and environmental obligations and stakeholder expectations. This allows for a best-in-class integrated asset planning process.

The primary function of all metering assets is to accurately measure, store and display the volume of gas consumed at a gas point in a safe-manner.

Prudent investment in metering technology and data management solutions is a key aspect in the development of new and open market services for the industry and energy customers.

7.3.2 Smart Metering

Bord Gáis Networks has actively engaged in and participated in the National Smart Metering Programme that is being coordinated by the CER. Bord Gáis Networks took primary responsibility for delivering the necessary metering and technical infrastructure in order to facilitate the commencement of a Gas Customer Behaviour Trial (CBT). The CBT commenced in December 2009 with smart metering equipment being installed at 1,925 residential customers' homes across the country. The customer behaviour trials were successfully concluded in May 2011. The results of these trials indicate that the benefits of having a smart-meter will contribute to a reduction in gas energy consumption. All of these results fed into the overall Customer Benefit Analysis document which can be viewed on the CER web site http://www.cer.ie

The CER has announced its decision to proceed to the next phase (Phase 2) of the national rollout programme of electricity and gas smart metering to all residential consumers and a significant proportion of small-to medium enterprise (SME) consumers. Phase 2 of the national rollout programme of electricity and gas smart metering will involve the high level design of the systems and infrastructure required to deliver a joint rollout of gas and electricity smart metering. The CER has published high level timelines with the rollout likely to begin in 2016.

The smart metering rollout is likely to leverage a single communications infrastructure for both gas and electricity smart metering. Smart metering is likely to lead to significant changes in the gas market code of operations as well as Bord Gáis Networks internal business processes due to the dramatic increase in energy consumption data.

Smart meters can facilitate improving energy efficiency by empowering consumers with more detailed, accurate, and timely information regarding their energy consumption and costs, thus helping consumers reduce any unnecessary energy usage.

The benefits of smart metering are recognised internationally and there are a number of key EU legislative instruments promoting smart metering to ensure that customers are properly informed of actual energy consumption and costs frequently enough to enable them to regulate their energy consumption. Smart meters are the next generation of meters, which can replace existing electro-mechanical and diaphragm meters and offer a range of benefits for both the individual gas and electricity consumer. It is intended that Gas and Electricity Smart Metering would be rolled out on a shared communication infrastructure. This effectively combines efficiencies and leverage of costs.

Smart Metering will deliver significant economic and environmental benefits to the Irish economy and consumer. It will enhance customer service allowing for more accurate billing as well as improved services for Pre-Pay and vulnerable customers. It will also lead to a reduction in carbon emission. The customer will be able to monitor their gas consumption by viewing an In Home Display (IHD) unit and also using their customer data portal where all detailed information specific to their energy consumption and billing will be held.

7.3.3 Domestic Meter Replacement Programme

The Domestic Meter Replacement Programme agreed with the CER and the Director of Legal Metrology continued throughout 2011 and is due to be completed towards the end of 2012 with over 70,000 'Smart-Ready' ultrasonic meters replacing older diaphragm gas meters.

Figure 7.4: Domestic Smart Meter

These 'Smart-Ready' meters can be upgraded to smart meters or prepayment meters by adding a communications module to the base meter. This provides a low-risk and economical pathway for upgrading to full smart-metering at a future date. It also helps to future-proof any smart-metering solution, as future technology upgrades can be accommodated by changing the communications module and leaving the existing base meter in place.

7.3.4 Prepayment Metering

Bord Gáis Networks with the agreement of the Commission for Energy Regulation (CER) and the Natural Gas Suppliers has operated a prepayment meter system since 2008. During 2011 there has been a notable increase in the number of prepayment meters installed.

Prepayment metering allows gas customers to purchase their credit at vending outlets and apply that credit to their meters. In this way, the customer can better manage their energy expenditure in a controlled way and thus avoid receiving a large bill at the end of the billing period. The customer uses a gas card to purchase credit. This purchase can take place at any Payzone outlet. The purchased credit is then relayed on the gas card back to the prepayment meter.

Figure 7.5: Prepayment Meter

The prepayment meter solution offers many benefits to the customer:

- Improved management of gas bills.
- Smaller payment amounts spread over a longer period of time.

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- No unexpectedly large bills and associated problems.
- Better monitoring and awareness of energy consumption leading to improved energy conservation.
- Control of own usage and payment. Ability to build up credits for periods of higher usage.
- Greater participation in the billing process leads to increased customer satisfaction.
- There is no requirement for regular meter reading and associated access problems, no meter disconnection or reconnection fees along with Improved Social Welfare payment receipt system.
- Pre-Pay meters also help landlords avoid large bills issues when tenants move out.

The prepayment meter is modular in design and has the advantage of being able to revert to a credit meter mode of operation by removing the Prepayment Module. This meter can also become a full Smart Meter by addition of a communications module to the base meter.

7.3.5 Industrial Meter Replacement Programme

Bord Gáis Networks will commence an Industrial Commercial Meter Replacement Programme during 2012. This programme will involve the non-daily metered (NDM) installations connected to the low and medium pressure distribution network. This work will cover all low and medium pressure non-daily metered (NDM) distribution sites in the industrial/commercial sector with meters from G16 upwards and constructed before 1991. The work will involve the replacement of meters, conversion of site fabricated skids to factory built module assemblies where feasible, compliance with ATEX and venting requirements and general tidy up of each site. Flow conversion and telemetry units are being provided at selected sites. These conversion units will provide pressure/temperature and compressibility conversion for accurate metering and relay network pressure via SCADA. These sites are also being fitted with low cost pulse repeaters to relay daily volumetric consumption.

The new meters will incorporate high integrity outputs making them smart-ready. This will include low cost pulse counting equipment in the majority of the meters to relay daily consumption to Bord Gáis Networks and to the end user over the Internet via the portal www.meter.ie .

This allows the customer to have visibility of usage on a daily basis though a dedicated and easy to use web portal.

Volume conversion devices will be fitted to the larger installations to improve overall metering accuracy and also provide telemetry information via SCADA of pressures and flow rates.

7.3.6 Meter Maintenance Programmes

There is a requirement for on-going maintenance of the Prepayment, Smart-Meters and communications modules, e.g. routine firm-ware and software security updates. These meters are battery powered and there will be an ongoing requirement to replace these as time progresses.

Bord Gáis Networks will actively carry out a battery replacement programme and where necessary module upgrade commencing in 2012.

The benefits in carrying out a battery replacement programme will avoid any inconvenience the customer would face in the event that they could not consume gas at their premises.

7.3.7 Meter Sampling Programmes

Bord Gáis Networks, in line with its Meter Technical Policy, sends meters for evaluation to an independent test centre. A sample of meters is taken from each meter population and sent away for independent testing. The results from the meter testing programme are used to identify meter populations in need of replacement.

7.4 Communications and Instrumentation

7.4.1 SCADA

Supervisory Control and Data Acquisition (SCADA) is used extensively to monitor and control the pipeline network. A Honeywell Experion SCADA system with Plant Historian is used for monitoring and controlling the transmission network. The distribution network is monitored by a separate SCADA system, which currently is hosted on an Invensys Wonderware and Industrial SQL Server. The central equipment for both transmission and distribution is hosted in a purpose built data centre facility in Gasworks Road and a disaster recovery facility in the Midleton compressor station.

Table 7.1: Summary of SCADA system

Item	Transmission	Distribution
System	Honeywell Experion	Invensys Wonderware
Capacity	65,355 points	20,000 points
Installations monitored	220	406
Clients	55	30
Communications	Leased lines, text and radio dialup, mobile data, text and radio	Dialup lines, mobile data and text
Polling Frequency	5 secs	12 hours or on exception by alarm
24/7 monitoring	Gasworks Road, Cork	NSC, Finglas

The transmission network is monitored and remotely controlled on a 24/7 basis from the primary control room at Gasworks Road and in case of emergency from the disaster recovery control room at Midleton Compressor Station. The distribution network is monitored, on a 24/7 basis, from the Networks Service Centre building in Finglas.

The main aspects of the SCADA system is summarised in Table 7.1.

7.4.2 Remote Terminal Equipment

The SCADA system uses remote terminal units (RTU) to retrieve information from the transmission network. The RTU typically measures gas flows, pressures, temperatures, valve status signals, cathodic protection voltages and utility signals. The RTU have output capability which is used to remotely control strategically placed line valves which can be used in emergency to shutdown pipeline sections. Low cost dialup solutions are used to monitor distribution assets. There are approximately 130 transmission connected RTUs and 250 distribution SCADA nodes. Communication is by means of digital leased lines, dialup lines and by use of text and mobile data calls over mobile data links operating on the 2.5G and 3G standards.

In the Price Review period there are plans to extend, via SCADA, the number of live pressure measurements in the distribution network. The pressure readings will be retrieved using SCADA links to new and existing flow computers.

7.4.3 Cathodic Protection Monitoring

Cathodic Protection (CP) is used to mitigate the effects of corrosion on buried steel pipe work. Impressed current techniques are used for the majority of transmission cross country pipelines with sacrificial techniques used in urban areas covering transmission and distribution. There are over 4,000 test points and 90 transformer rectifiers. All transformer rectifier sites are monitored remotely and, in addition, over 170 data loggers which are installed in test posts, are used to record and monitor CP parameters remotely, are viewable over the Internet.

The care regime for the maintenance and upkeep of the CP assets is a combination of annual survey of all test points and rectifiers, and monthly monitoring using remote CP data logging devices. Close interval surveys are used to provide close and detailed inspection of pipelines once every five years for pipelines that cannot be surveyed online and ten years for all other pipelines. Differential current voltage gradient surveys (DCVG) are used to locate coating anomalies.

7.4.4 Instrumentation

Instrumentation is in place at all transmission installations to monitor process gas pressure, temperature, flow information, cathodic protection voltages and general ancillary signals such as 220V AC mains incomers, generator faults, intrusion detection etc. Sophisticated flow computers are used to correct for pressure and temperature at the metering element and so provide accurate billing data. All of these systems are tied into the telemetry units which are then relayed to Cork via the SCADA systems.

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Figure 7.6: Instrumentation at an AGI

7.5 Pipelines

The pipeline network is composed of high pressure cross-country and trans-national transmission pipelines and a lower pressure distribution network to transport gas to end users. The transmission system transports gas from producers or storage facilities at high pressure through steel pipes. The two interconnectors which cross the Irish Sea and deliver the majority of inventory to the island operate at pressures of 120 barg. The onshore system operates at three pressure tiers, rural cross country lines at 70 bar and with lower pressures prevailing in major cities and towns.

Distribution mains carry the gas at a lower pressure from the transmission pressure reduction stations for delivery to the end users. There are approximately 11,000 km of distribution mains and they are constructed primarily of high density polyethylene. Service pipes carry the gas from the main to the customer's meter.

There is a continuous programme to ensure the network complies with the relevant legislation, technical standards and codes of practice and that the pipeline assets are maintained in accordance with best international practice.

In recognition of the fact that third party damage poses the highest risk to both the transmission and distribution assets, a variety of measures and initiatives are in place to prevent accidental damage to the pipeline system. Last year a very successful transmission pipeline marker post replacement programme was carried out in the Cork region and this is now set to be replicated across the whole country. The new marking system is in line with the best in Europe and is constructed such that a marker can be seen in the line of sight at any point along the pipeline.

The Dublin 4 pipeline refurbishment programme was successfully completed last year and has significantly reduced the potential for an incident. Over the forth coming year similar pipeline refurbishment works are planned in Dublin, Limerick and Waterford.

These works will significantly reduce risk and increase public safety as older pipelines are replaced with more modern and superior strength lines to meet the demand and the changes in population density which has occurred in many urban centres in the last number of years.

7.6 Asset Integrity

Bord Gáis Networks designs, constructs and operates the natural gas pipeline network to the highest safety standards. As a result of extensive capital investment in recent years, together with very stringent operating and management procedures, the Irish pipeline network is amongst the most modern and safe in the world. Bord Gáis Networks has set safety as its top priority and considerable resources have been invested to ensure that our operations, procedures and processes benchmark favourably with the best of international utility safety standards.

The Asset Integrity team in conjunction with the Asset Owners, are responsible for formulating and implementing strategies which maximise the integrity of all asset categories within Bord Gáis Networks in the safest, most reliable and cost-effective manner.

Bord Gáis Networks recognise that third party damage is the single biggest threat to the integrity of the gas network. In 2011, a dedicated strategy group was put in place to review, improve and implement preventative measures to further decrease the potential for third

Figure 7.7: Negotiating Streets Congested with Services & Auger Bore Under Dart Line

party damage. The group will continue this work in 2012 and plan to introduce further enhancements to the Bord Gáis Networks Dial Before You Dig service. The service has experienced increased call numbers as a result of national advertising campaigns. The Asset Integrity team have also recently completed a detailed review of transmission pipeline marking arrangements and have completed a pilot project to trial new marker post designs and placement frequencies. The pilot project has been a success and it is now planned to expand it nationwide.

In line with best international practice and where allowed by Irish codes and standards, Bord Gáis Networks is moving towards a risk based maintenance and inspection regime and the Asset Integrity team have an integral role in this process. A risk based regime will allow Bord Gáis Networks to focus maintenance and inspection resources where they are most effective, resulting in increased asset safety and reliability while constraining costs. The recent introduction of new IT systems supports the move to such a regime.

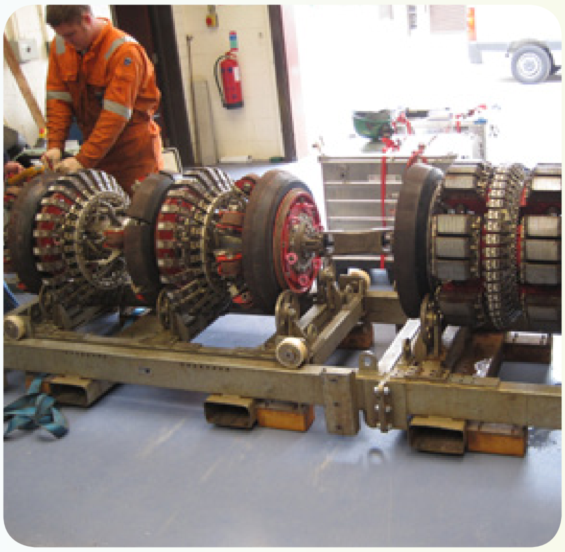
Bord Gáis Networks currently inspects a significant proportion of the gas transmission system using the latest technology in-line inspection tools. The remainder are checked using above ground inspection techniques. The Asset Integrity team are currently examining ways to further increase the system percentage internally inspected through the use of new in-line inspection technologies. Current inspection intervals will also be assessed in terms of a risk based approach.

ATEX is the name commonly given to the framework for controlling explosive atmospheres and the standards of equipment and protective systems used in them. It is based on the requirements of two European Directives, and it covers both electrical and mechanical installations and equipment and exists to ensure the safety of an installation during all phases in the lifecycle. Given the large number and wide geographical spread of Bord Gáis Networks's installations, ensuring and maintaining

Figure 7.8: Transmission Pipeline Marker Upgrade Pilot - Line of Sight Marking

7. Networks Asset Management & Development

Figure 7.9: Pipeline Inspection Gauge (PIG)



compliance with ATEX is a significant undertaking. Bord Gáis Networks has made good progress in this regard but intend to intensify efforts throughout 2012 by appointing a dedicated project manger and cross functional working group to complete the project.

7.7 Gas Quality

7.7.1 Physical and Chemical Properties

All gas entering the transmission network must comply with the gas quality specification as prescribed in the Code of Operations (available on the Gaslink website).

The gas combustion characteristics are measured online (calorific value, Wobbe index and relative density) by process gas chromatographs. These process gas analysers and associated software comply with relevant international standards and the online measurements are available live through SCADA to the Grid Control Centre in Cork.

The natural gas impurities are measured offline. Spot samples are taken monthly and analysed by an accredited laboratory to the appropriate standard methods.

Following a code modification in 2011 a revised gas quality specification is to be applied in the ROI. The new specification includes additional constituents and specifies a narrower Wobbe index range. Bord Gáis Networks is currently completing a comprehensive review of all entry point measurement arrangements to ensure that gas entering the network is fully compliant with the revised specification.

7.7.2 Odour

Natural gas is odourless and for safety reasons a proprietary odorant is added to the gas entering the network. This differs from practice in the UK and most other European transmission networks where the gas remains unodourised until it enters the lower pressure distribution networks.

Gas delivered into the network is odourised on the basis of a logarithmic delivery scale at the rate of approximately 6 mg/m^3 to achieve an Odour Intensity (OI) of 2 on the Sales Scale.

To verify the odour intensity of gas delivered to consumers, gas samples are taken from locations throughout the network, analysed by a gas chromatograph and odour intensity calculated. Odour intensity reports are issued monthly.

7.8 Natural Gas as a Transport Fuel

Bord Gáis Networks has a strategic objective to grow the size of the Irish natural gas market and, thereby, improve the utilisation of its gas transmission and distribution system. In accordance with this objective, Bord Gáis Networks is developing the application of natural gas as a transport fuel in Ireland.

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 an annual growth of approximately 30%. According to the Natural Gas Vehicle Association of Europe, in 2011 there were over 14 million NGVs worldwide, accounting for 1.35% of the total global vehicle population.

This growth of NGVs is driven by a number of important factors especially the economic and environmental benefits:

- Economic – According to NGVA Europe CNG is typically 30 – 60% cheaper than traditional fuels (petrol or diesel) across Europe (subject to local tax/excise duties).
- Environmental – Significant reductions in emissions including substantially reducing Carbon Dioxide, Particulate Matter and Nitrogen Oxide.
- The use of CNG will also reduce the dependency on oil and diversify the energy mix within the Irish transport system.

Bord Gáis Networks is currently involved in a number of activities in this area including:

- Examining the lessons learned from developed CNG markets.
- Analysing CNG operating costs through its use within the Bord Gáis Networks fleet.
- Planning a 'fast-fill' CNG refuelling unit for use within Bord Gáis Networks fleet. This will refuel vehicles in approximately 2-4 minutes.
- Meeting with stakeholders to ensure a cross-functional industry partnership. In November 2011, Bord Gáis Networks facilitated the first Irish NGV conference in Dublin, which was attended by over 150 transport and energy industry professionals.
- Liaising with interested parties to commercially use CNG within captive fleets.

Figure. 7.10: Natural Gas Vehicle

8. Security of Supply

8.1 Overview of Legal Framework

Natural gas plays a substantial role in supporting Ireland's economy, with gas accounting for approximately 30% of the ROI's TPER and approximately 55% of Ireland's electricity generation. Maintaining secure supplies of natural gas to Ireland is therefore essential in order to support economic activity.

The vast majority of Ireland's gas is supplied through the Moffat Entry Point in Scotland. There are two sub-sea pipelines interconnecting Ireland with Scotland. A third sub-sea pipeline links Northern Ireland to Scotland. All three sub-sea pipelines are supplied via a single onshore pipeline in Scotland.

In December 2010 the European Commission issued EU Regulation No 994/2010 which puts in place measures to safeguard security of gas supply. The legislation puts several obligations on Member States to deal with a gas supply interruption.

The legislation puts an obligation on the competent authorities in each Member State to provide:

- A Risk Assessment
- A Preventive Action Plan
- An Emergency Plan

This work is being undertaken by the CER, as the competent authority in Ireland. The CER have carried out and published the risk assessment in 2012, outlining their findings in relation to Ireland meeting the Infrastructure Standard as required by the Regulation. The CER have also issued a draft Preventive Action Plan and a draft Emergency Plan.

The regulation EU 994/2010 puts forward the principal of N-1. This requires that the Member State's Competent Authority shall ensure that, in the event of the loss of the single largest piece of gas infrastructure, the capacity of the remaining infrastructure can satisfy the total gas demand of the calculated area during a day of exceptionally high demand. A high demand event is assumed to occur once every twenty years. Gaslink and Bord Gáis Networks assisted the CER in completing the Risk Assessment by carrying out various N-1 calculations and producing a technical risk assessment which examined the principal failure modes that could threaten the security of supply through the Moffat Entry Point as Ireland's single largest piece of infrastructure.

The Risk Assessment also defines the 'Protected Customers' whose gas supplies are to be ensured under various scenarios as per the Regulation.

Studies indicate that the likelihood of a major supply interruption resulting in a prolonged and severe shortfall in gas supply to the island of Ireland is very low. Although the risk is remote, it nonetheless remains that the Risk Assessment shows that Ireland is unable to meet the N-1 standard in the short term, particularly with the continued delay of supply from the Corrib gas field.

The Regulation also provides that the competent authority may deem the obligation to be fulfilled at a regional level instead of at a national level, where appropriate, according to the completion of a Risk Assessment. As detailed in the Risk Assessment Ireland cannot meet the N-1 standard in the short term.

Accordingly, the CER requested DECC as the Competent Authority in the UK to agree to a Regional Approach to fulfilling the standard as provided for in the Regulation. DECC acceded to this request, and the CER is currently working with them on a protocol to be adopted to ensure both jurisdictions can continue to meet their obligations under the Regulation into the future.

8.2 Existing Operational and Planning Arrangements

The CER has designated Gaslink to undertake the role of the National Gas Emergency Manager (NGEM) in accordance with SI 697 of 2007. Gaslink, under its TSO and DSO licence obligations, has produced a Natural Gas Emergency Plan (NGEP), which has been approved by the CER and details the roles and responsibilities of all natural gas undertakings in the event of a potential or actual gas supply emergency.

The NGEM is responsible for managing any potential or actual gas supply emergency, in accordance with the provisions of the NGEP. The NGEM acts as the incident controller and is responsible for declaring an emergency.

Bord Gáis Networks supports the NGEM by acting as the interface with other natural gas undertakings, producers, storage operators and any connected system operators, and by implementing the NGEM instructions.

Bord Gáis Networks has put in place emergency arrangements with other connected systems operators; PSE Kinsale Energy, PTL, the MEA and National Grid (GB) and EirGrid. Bord Gáis Networks has also clarified with the Network Emergency Coordinator (NEC) in GB, the arrangements that will apply in the event of a Network Gas Supply Emergency (NGSE) in GB.

A Gas Emergency Response Team (GERT) is in place as part of the NGEP. This group convenes in the event of an actual emergency and includes representatives from Bord Gáis Networks, Gaslink, EirGrid and CER/DCENR.

In addition to the GERT, there is also a Task Force on Emergency Procedures (TFEP), which is chaired by the CER and includes representatives from the Department of Communications, Energy and Natural Resources (DCENR), Gaslink, Bord Gáis Networks, EirGrid and ESB Networks.

The TFEP is responsible for ensuring that coordinated procedures are in place to manage a supply emergency on the gas and electricity systems, and that an emergency on one system does not lead to an emergency on the other. The first TFEP report was published in 2007 and included recommendations to enhance the existing arrangements and procedures, including:

- Giving EirGrid a role in the curtailment of gas supplies to power stations during a natural gas supply emergency, in order to mitigate as far as possible the impact on electricity supplies; and

- Requiring power stations to hold adequate stocks of secondary fuels, and testing their ability to switchover to these secondary fuels in an emergency.

As part of the NGEP, a Gas Emergency Planning Team (GEPT) meets with a view to further developing the emergency arrangements contained in the NGEP. This team includes Bord Gáis Networks, Gaslink, EirGrid and CER/DCENR. This team also discusses forthcoming gas emergency exercises and exercises already conducted. As part of a continuous review of the NGEP, the plan is currently being updated to a 4-step process in order to align it will National Grid's revised NGSE plan.

Exercise Avogadro was conducted between operators/regulators and Government Departments in Ireland and the UK in the summer of 2010, and Exercise Saffron in the Autumn of 2011. These exercises tested the communications protocols between government and industry in the event of a major gas supply emergency. The exercise also included liaison with the equivalent authorities in Northern Ireland. The exercises were deemed successful and a number of initiatives have stemmed from the lessons learned.

In addition to planning arrangements for potential or actual gas supply emergency's, Bord Gáis Networks put in a place a number of preventative measures to reduce the risk of an emergency.

Grid Control, a department within Bord Gáis Networks, is responsible for the 24 hour technical operation and supervision of the gas network using a sophisticated Supervisory Control and Data Acquisition (SCADA) system which captures and presents live data from each above ground installation (AGI). System operating limits are applied in SCADA and any violation results in a system alarm, which is immediately investigated by Grid Control. Some alarm events are escalated to a Field Operations team to resolve, who operate on a 24 / 7 on-call basis all year round.

Emergency repair arrangements are maintained with contractors that would allow the timely repair of any damage to the transmission network if required. In addition to this 24 hour operation and supervision of the network, security cameras are installed and monitored at various key stations and the transmission pipeline network is monitored regularly by helicopter and line walks.

Bord Gáis Networks considers safety as core to all its activities. Bord Gáis Networks continues to place safety as a top priority in its business and for all its customers, particularly through its safety awareness media campaigns; the Gas Emergency Service, Dial Before You Dig, promotion of Registered Gas Installers (RGIs) and public awareness of the dangers of Carbon Monoxide.

9. Commercial Market Developments

9.1 Gaslink: Independent System Operator

In accordance with Licences granted by the Commission for Energy Regulation (CER), Gaslink, as the Independent System Operator operates, maintains and develops the ROI gas Transportation System. BGÉ, as System Owner, holds a licence relating to its ownership of the transportation system.

The key role and responsibilities of Gaslink are as follows:

- To operate, maintain and develop, under economic conditions secure, reliable and efficient transmission and distribution systems with due regard to the environment;
- To provide any natural gas undertaking with sufficient information to ensure that transport of natural gas on the transmission system may take place in a manner compatible with the safe, secure and efficient operation of the network;
- To provide users of the transmission system with the information they need for efficient access to the transmission and distribution systems;
- To procure the energy it uses for the carrying out of its functions according to a transparent, non-discriminatory and market based procedure subject to CER approval;
- To adopt rules for the purposes of balancing the gas system which are objective, transparent and non-discriminatory; and
- To report to the CER, as outlined in the Gas (Interim) (Regulation) Act, 2002, and in respect of any other matters as the CER may specify.

Gaslink is an independent subsidiary of BGÉ in terms of its organisation and decision making processes, when executing its responsibility for the operation of the transmission and distribution systems.

Gaslink identifies all work necessary for the operation, maintenance and development of the gas Transportation System, and instructs BGÉ to carry out works in accordance with the Operating Agreement (specified in the legislation and approved by the CER). Gaslink holds two licences from the CER for the operation of the ROI transmission and distribution systems, which inter alia cover the following areas:

- Connection to the transmission and distribution systems;
- Transmission and distribution system standards;
- Operating security standards;
- Provision of metering and data services; and
- Provision of services pursuant to the Code of Operation (the "Code").

9.2 European Developments

The Third Gas Package is bringing significant change to the legislative and regulatory frameworks covering gas transportation which will result in considerable redefinition of the transportation arrangements at interconnection points across Europe such as Moffat. The 3rd Package consists of the following key elements:

- Directive 2009/73/EC which introduces new requirements related to the unbundling of vertically integrated gas utilities;
- Regulation (EC) No. 713/2009 which mandates a new Agency for the Cooperation of Energy Regulators (ACER); and
- Regulation (EC) No. 715/2009 which requires, amongst other things, the setting up of European Network Transmission System Operators in Gas or ENTSOG.

ENTSOG was formally established in 2009 and European TSOs have been obliged to cooperate with each other since the Directive came into effect. This cooperation happens through participation in ENTSOG European Network Code development working groups. These network codes represent a key pillar of the European Commission's strategy of creating a single market in energy through enhancing cross-border trade and competition. Gaslink, the Irish TSO and one of the founding member of ENTSOG, is participating actively with fellow European TSOs on the code development process.

ACER, the agency for the Cooperation of Energy Regulators (The Agency), a new entity created as part of the 2009 Third Gas Package has issued framework guidelines on the Capacity Allocation Mechanism (CAM), Gas Balancing, Interoperability, and a Tariff framework guideline is currently being scoped out. ENTSOG has submitted a CAM Network Code, which accords with the relevant framework guideline, and is currently consulting on a draft Balancing Network Code.

9.3 New Connections

Gaslink continues to engage with parties wishing to connect to the transmission and distribution networks. In accordance with the Operating Agreement, Gaslink undertakes all the large connection agreements to the transmission system and manages the provision of all other connection agreements undertaken by Bord Gais Networks on Gaslink's behalf. All new connections are managed in compliance with the CER approved Connections Policy. This Policy sets out the criteria for connecting new customers to the gas network.

In 2012 a review of the policy will take place in conjunction with Bord Gáis Networks and the CER. One of the main areas to be reviewed is the connection process for those interested in connecting biomethane generating facilities. Gaslink has been engaging with the CER on this matter, and it is Gaslink's intention to consider the inclusion of specific requirements in the policy that governs the terms for connection of such entry points to the gas network.

In conjunction with the CER, Gaslink will review an appropriate mechanism for renewable gas entry points and together develop proposals as appropriate. These proposals will endeavour to bring clear and transparent arrangements which will clarify the approach for these facilities which should assist the wider use of renewable gas, ensuring non-discriminatory access to the gas network.

9.4 Moffat

9.4.1 Selling Gas at the NBP

In response to requests from the market for the facility to sell gas into Great Britain (GB) at the National Balancing Point (NBP) from the Irish market, Gaslink developed a virtual reverse flow product at the Moffat Entry Point. Physically the flow remains unidirectional but through this new product, contractual reverse flow of the gas is possible. Moffat is now designated as an Exit Point and Virtual Entry Point from the GB transmission system.

9.4.2 NTS Exit Reform

93% of the Irish gas requirements and 100% of Northern Ireland and Isle of Man gas is supplied via the Moffat interconnection point with the GB system operated by National Grid. The current arrangement for booking capacity to ship gas through the inter-connector pipelines is a 'Ticket to ride' process. This means that GB parties can only book capacity at Moffat if they were nominated to do so by a counter party downstream of Moffat.

As part of what is commonly termed NTS Exit Reform, the Office of Gas and Electricity Markets (OFGEM), approved a modification (UNC 195AV) to the GB code in early 2009 which puts in place a user commitment model at Moffat, where ultimately, parties will be required to book exit capacity several years in advance in order to ensure access to such capacity. The new arrangements come into full effect on 30th of September 2012 and will result in substantial changes to the allocation of NTS exit capacity at Moffat. One key impact is the abolition of the Downstream Capacity Register which facilitated the ticket to ride required by upstream shippers in order to procure exit capacity.

9. Commercial Market Developments

9.5 CAG Summary

"The All-island Energy Market Development Framework" paper (agreed by Irish and Northern Irish Ministers in November 2004) set the scene for the review of energy markets on an All-Island basis. The Single Electricity Market (SEM) was the first phase in this development. In establishing Common Arrangements for Gas (CAG), the CER and the Northern Ireland Authority for Utility Regulation (UREGNI), plan, subject to the approval of the relevant authorities, to progress phase two of this energy management harmonisation work through the facilitation of the operation of the natural gas market in Ireland and Northern Ireland on an all-island basis.

The implementation of CAG may bring a range of benefits; enhanced SOS, enhanced interconnectivity of gas networks on the Island, optimise future investments and enhanced competition; however, realising these benefits is subject to further investment/costs. These costs should be apportioned in a manner that reflects the level/scale of benefits realised by each of the two jurisdictions on the Island.

The first Joint Gas Capacity Statement (JGCS) was produced in 2009, as part of the CAG project. The JGCS 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 a number of years. It constitutes an important step in developing a harmonised approach to security of supply on the island under the CAG project. This work will be central to the CAG project and the systems operations function going forward.

Current Status:

- The Regulatory Authorities has initiated a number of preliminary CAG work streams.
- Currently the CER and UREGNI are progressing, with external consultants, some further analysis on, amongst other things, the provision of balancing services.
- Work on the 2012 Joint Gas Capacity Statement (JGCS) is being currently progressed, with an expected publication date in the 3rd quarter of 2012.

9.6 Gormanston Exit Point

In April 2012, Gormanston was designated as the Relevant Point on the South North Pipeline (SNP). The Gormanston interconnection point facilitates the physical forward flow of gas from the Interconnector System to NI as well as virtual reverse flow in the opposite direction.

Whilst working towards greater integration of systems, Gaslink and BGE(UK) have endeavoured to ensure the necessary arrangements were developed to allow the SNP to be commercially operational. Commercial arrangements to facilitate the Forward Flow and Virtual Reverse Flow products were finalised on the 1st of July 2012.

Appendix 1: Demand Forecasts

The demand forecasts are summarised in Tables A1.1 – A1.3. Table A1.4 presents the various supply sources by entry point, both existing and proposed. The values represent the maximum supply volume each source could potentially provide.

The ROI demand is broken down by sector, while the total demand is given for NI and the IOM. The forecasts are based on the following weather scenarios:

- Table A1.1: Peak day gas demand under severe 1-in-50 weather conditions, i.e. weather so severe that statistically it is only likely to occur once every 50 years;
- Table A1.2: Peak day gas demand under 'average year' weather conditions, i.e. the weather conditions that typically occur each year; and
- Table A1.3: Annual gas demand in average year weather conditions.

The NI peak day demand used for both the 1-in-50 and average year weather forecast is based on information provided by the Northern Ireland Utility Regulator (UREGNI). The IOM peak day is based on information provided by the Manx Electricity Authority (MEA).

The electricity demand for the average year is as per EirGrid's All Island Generation Capacity Statement 2012-2021 under the median electricity demand forecast. The 1-in-50 year electricity demand is calculated by projecting forward the actual peak of 5,090MW and growing this figure forward, in line with the median electricity demand forecast growth rate.

The weather correction is only applied to the distribution connected load, i.e. primarily to the residential and small I/C sectors. There is no weather correction applied to the power sector gas demand forecast.

Table A1.1: Peak Day Demand (1 in 50 weather) & Base Supply by Gas Year

	12/13 GWh/d	13/14 GGWh/d	14/15 GWh/d	15/16 GWh/d	16/17 GWh/d	17/18 GWh/d	18/19 GWh/d	19/20 GWh/d	20/21 GWh/d
Demand									
Power	133.8	141.3	143.2	158.0	161.3	164.4	166.9	170.0	173.7
I/C	55.7	56.9	58.2	59.1	60.0	61.1	62.2	63.3	64.0
RES	69.5	69.0	68.5	68.1	67.6	67.2	66.7	66.3	65.9
Own use[2]	5.1	5.2	5.5	4.6	4.7	5.1	5.1	5.2	5.2
Sub total	264.1	272.4	275.4	289.8	293.6	297.8	300.9	304.8	308.8
Injection[1]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IOM	5.7	5.7	5.7	5.8	5.8	5.8	5.8	5.9	5.9
NI	89.2	87.9	87.1	85.6	86.6	87.6	88.7	89.7	91.0
Total	359.0	366.0	368.2	381.2	386.0	391.2	395.4	400.4	405.7

Notes

1 Injection refers to storage injections from the transmission system into Kinsale and Larne Storage

2 Own-use refers to fuel-gas used by the transmission system to transport the gas, e.g. fuel-gas used the compressor stations and heat exchangers at Above Ground Installations (AGIs)

Table A1.2: Peak Day Demand (Average Year Weather) & Base Supply by Gas Year

	12/13 GWh/d	13/14 GWh/d	14/15 GWh/d	15/16 GWh/d	16/17 GWh/d	17/18 GWh/d	18/19 GWh/d	19/20 GWh/d	20/21 GWh/d
Demand									
Power	126.4	131.5	133.8	142.1	145.6	147.4	151.9	154.9	157.0
I/C	48.3	49.4	50.4	51.2	52.0	53.0	53.9	54.9	55.5
RES	54.7	54.3	54.0	53.6	53.2	52.9	52.5	52.2	51.8
Own use	3.4	3.5	3.7	3.0	3.1	3.3	3.4	3.5	3.6
Sub total	232.8	238.7	241.9	249.9	253.9	256.6	261.7	265.5	267.9
Injection	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IOM	5.1	5.2	5.2	5.2	5.3	5.3	5.3	5.4	5.4
NI	70.4	69.2	68.4	67.0	67.7	68.3	68.9	69.6	70.5
Total	308.3	313.1	315.5	322.1	326.9	330.2	335.9	340.5	343.8

1 2 3 4 5 6 7 8 9

Appendix 1: Demand Forecasts

Table A1.3: Annual Demand (Average Year) & Base Supply Scenario by Gas Year (TWh/y)

	12/13 TWh/y	13/14 TWh/y	14/15 TWh/y	15/16 TWh/y	16/17 TWh/y	17/18 TWh/y	18/19 TWh/y	19/20 TWh/y	20/21 TWh/y
Demand									
Power	33.26	34.83	35.93	36.44	38.25	39.09	41.17	40.64	41.41
I/C	13.11	13.36	13.63	13.81	14.00	14.24	14.48	14.73	14.89
RES	7.92	7.87	7.81	7.76	7.70	7.65	7.60	7.54	7.49
Own use	0.81	0.80	0.81	0.49	0.56	0.64	0.67	0.68	0.72
Sub total	55.10	56.86	58.18	58.50	60.51	61.62	63.92	63.59	64.51
Injection	2.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
IOM	1.31	1.34	1.35	1.36	1.36	1.37	1.38	1.39	1.40
NI	15.95	16.16	16.33	16.48	16.61	16.75	16.88	16.75	16.94
Total	74.87	74.36	75.86	76.34	78.48	79.74	82.18	81.73	82.85

Table A1.4: Maximum Daily Supply Volumes

	12/13 GWh/d	13/14 GWh/d	14/15 GWh/d	15/16 GWh/d	16/17 GWh/d	17/18 GWh/d	18/19 GWh/d	19/20 GWh/d	20/21 GWh/d
Supply									
Corrib	0.0	0.0	0.0	92.9	84.7	72.4	72.7	70.0	61.8
Inch[1]	33.7	33.1	17.4	9.8	5.3	0.0	0.0	0.0	0.0
Moffat[2]	342.4	342.4	342.4	320.3	320.3	320.3	320.3	320.3	320.3
Total	376.1	375.5	359.8	423.0	410.3	392.7	393.0	390.3	382.1

[1] Combination of existing storage and forecast production levels
[2] The capacity of Moffat is based on the capacity of Beattock compressor station

The forecast assumes that the peak day gas demand of the power sector is coincident with that of the residential and I/C sectors, as this gives the worst case scenario for gas system planning purposes.

The power peak day gas demand forecast assumes that all of the non gas fired thermal power stations are available on the day, i.e. all of the peat, coal and oil-fired power stations. If there is a forced outage of one or more of the non gas-fired thermal power stations, then the peak day gas demand of the sector may be higher than indicated in the above forecasts.

Appendix 2: Historic Demand

Historic Daily Demand **by** Metering Type

The historic demand data in chapter 4 is presented by sector (i.e. residential, I/C and power), as this is more useful for forecasting purposes and is also considered to be a more familiar classification for the users of this document. The actual demand data is collected by metering type:

- Large Daily Metered (LDM) sites with an annual demand of 57.5 GWh/y or greater, and includes all the power stations and the large I/C sites;
- Daily Metered (DM) sites with an annual demand greater than 5.6 GWh/y and less than 57.5 GWh/y, and includes the medium I/C, hospitals and large educational facilities etc; and
- Non-Daily Metered (NDM) with an annual demand of 5.6 GWh/y or less, and includes the small I/C and residential sectors.

The demands of the above categories are then recombined into the following categories for reporting and forecasting purposes, using the monthly billed residential data to split the NDM sector into its residential and I/C components:

- Power sector: The individual power stations are separated out from the LDM total;
- The I/C sector: Which is comprised of the demand from the remaining LDM sites, the DM sector and the NDM I/C sector (calculated as the residual of the total NDM demand and the residential demand); and
- Residential sector: Which is calculated as a percentage of the NDM demand, using the ratio of the total billed monthly NDM and residential demand.

The historical daily demand on the transmission and distribution systems is shown in Fig. A2.1 and A2.2, with the corresponding peak day, minimum-day and annual demands tabulated in Table A2.1. The transmission and distribution daily demands have been broken down into the following sub-categories:

- Transmission (Tx) demand has been subdivided into the power sector demand, with all of the remaining LDM and DM I/C demand combined into the TX DM I/C category; and
- Distribution (Dx) demand has been subdivided into the NDM demand, with all of the remaining LDM and DM I/C demand combined into the DX DM I/C category.

It can be seen from Fig. A2.1 that the distribution connected demand is very weather sensitive, peaking in the colder winter period and falling off in the warmer summer period. The NDM demand is particularly weather sensitive, as it includes the residential and small I/C sectors, which primarily use gas for space heating purposes.

The transmission connected demand on the other hand, does not appear to be particularly weather sensitive. The gas demand of the power sector in particular is driven by relative fuel prices rather than the weather (although the gas price can be weather related as well).

The peak day demands shown in Table A2.1 represent the coincident peak day demands, i.e. the peak day demand of each sector on the date of the overall system peak day demands. Each sector may have had a higher demand on a different date. The non-coincident peak day demand of each sector is shown in Table A2.2.

Appendix 2: Historic Demand

Fig. A2.1: Historical Daily Demand of Transmission Connected Sites

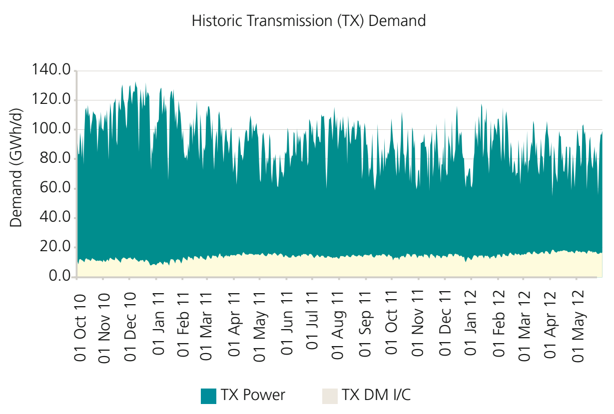


Fig. A2.2: Historical Daily Demand of the Distribution Connected Sites

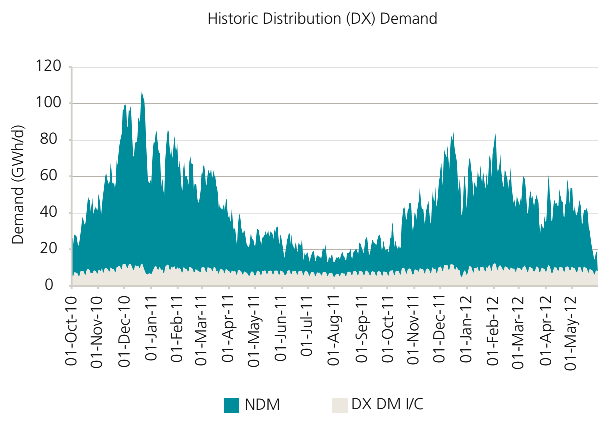


Table A2.1: Historical Coincident Peak Day and Annual Demands

	2006/07 (GWh)	2007/08 (GWh)	2008/09 (GWh)	2009/10 (GWh)	2010/11 (GWh)	2011/12 (GWh)
Peak Day						
TX Power	111.2	119.7	126.4	134.3	132.2	116.3
TX DM I/C	11.2	10.7	10.4	9.1	12.0	15.5
DX DM I/C	10.8	11.2	11.0	11.7	12.3	11.9
DX NDM	71.4	74.1	79.7	92.5	89.5	68.0
Total ROI	204.6	215.7	227.5	247.6	246.0	211.7
Annual						
TX Power	34,688	37,758	36,007	39,338	35,983	30,085
TX DM I/C	4,029	3,793	3,518	3,701	4,360	5,641
DX DM I/C	2,827	2,828	2,835	2,858	3,020	3,077
DX NDM	11,345	12,125	12,374	12,530	12,363	10,606
Total ROI	52,889	56,504	54,734	58,427	55,726	49,409

1 Power sector demand includes the gas demand for those I/C connections which generate electricity for their own use less process gas

Table A2.2: Historical Non-coincident Peak Demands by Sector

	2006/07 (GWh/d)	2007/08 (GWh/d)	2008/09 (GWh/d)	2009/10 (GWh/d)	2010/11 (GWh/d)	2011/12 (GWh/d)
Peak Day						
TX Power	123.1	129.3	135.7	134.3	133.0	117.9
TX DM I/C	13.7	12.9	12.7	13.7	17.3	18.8
DX DM I/C	11.3	11.3	11.2	11.8	12.3	12.7
DX NDM	72.1	74.1	79.7	95.2	94.9	73.0
Total ROI	220.2	227.6	239.3	255.0	257.5	222.4
Peak Day by Sector						
Power	123.1	129.3	135.7	134.3	133.0	117.9
I/C	47.1	46.9	46.8	51.8	54.5	53.2
RES	50.0	51.4	56.8	68.9	69.9	51.3
Total ROI	220.2	227.6	239.3	255.0	257.4	222.4

1 Power sector demand includes the gas demand for those I/C connections which generate electricity for their own use less process gas

Appendix 3: Energy Efficiency Assumptions

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;

Impact on Residential Gas Demand

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

- Incremental gas demand from new residential connections will 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 will 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.

Table A3.1: NEEAP Energy Efficiency Savings Targets

	2010 PEE 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
Building Regulations 2005	185	370	560
Building Regulations 2010	0	630	1,360
SEI energy agreements (IS 393)	465	685	4,070
SEI small business supports	160	330	565
Existing ESB DSM programmes	380	410	435
Renewable Heat Deployment programme	360	410	410
ACA for energy efficient equipment	100	400	800
Total business and commercial savings	1,790.0	3,375.0	8,340
Other sectors			
Transport	775	3,105	4,670
Energy Supply sector	275	300	365
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

Appendix 3: Energy Efficiency Assumptions

The average annual gas consumption of all new residential customers connected during the 2005/06 gas year was approximately 12.3 MWh/y. The NDS forecast assumes the average gas consumption of each new customer connected by 2012/13, will reduce by 60% to 4.9 MWh/y.

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 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 NDS forecast assumes that:

- Total energy efficiency savings of 5,614 GWh in residential heat demand between 2010/11 and 2019/20 from the above measures (annual reduction of 561 GWh/y);
- Approximately 27% of this target reduction will be achieved in gas-fired residential homes, based on the gas share of residential heat in 2010, i.e. the gas share of total residential TFC after excluding the electricity and renewable components; and
- This would lead to a reduction of 152 GWh/y in residential annual gas demand, which is equivalent to 1.8% of the residential gas demand in 2011/12.

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 NDS 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 (per the NEEAP), 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 19.3% up to 2016 and 21.4% up to 2020, based on gas share of total I/C TFC in 2010 (of 23.0%) 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 65.1 GWh/y in I/C annual gas demand up to 2014/15, and 266 GWh/y from 2015/16 onwards (which is equivalent to 0.5% and 2.1% of the 2011/12 I/C annual demand respectively).

Appendix 4: Transmission Network Modelling

The purpose of the hydraulic network modelling is to test the adequacy of the existing ROI transmission network for a forecast demand under a number of supply scenarios, establishing where pressures are outside acceptable operational boundaries or where there is insufficient capacity to transport the necessary gas. This chapter summarises the results of the network analysis carried out for this NDS.

Network analysis was carried out using hydraulic network modeling software, Pipeline Studio®. A single hydraulic model of the Interconnector and ROI onshore transmission systems[20] was constructed using Pipeline Studio®. This simulation software was configured to analyse the transient 24 hour demand cycle over a minimum period of three days to obtain consistent steady results.

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

These demand days, which were generated from the gas demand forecast, have been chosen as they represent the maximum and minimum flow conditions on the transmission system.

The ability of the ROI transmission system to accommodate the forecast gas flow requirements was validated against the following of criteria;

- Maintaining the specified minimum and maximum operating pressures at key points on the transmission systems;
- Operating the compressor stations within their performance envelopes; and
- Ensuring gas velocities do not exceed their design range of 10 – 12 m/s

Entry Point Assumptions

The main Entry Point assumptions are summarised in the following table;

Table A4.1: Entry Point Assumptions

	Moffat	Inch	Corrib	Shannon
Pressure (barg)	47.0[1]	30.0	Up to 85.0	Up to MOP[3]
Gross Calorific Value (mj/scm)	39.8	37.8	37.5	40.5
Max Supply (mscmd)	31.0[1]	3.2	8.92[2]	11.3

[1] Reduces to 45 barg and 29.0 mscmd from 2015/16 (see section 6.5.3)
[2] Maximum daily supply capacity for 1st year of production
[3] Maximum Operating Pressure of the pipeline

As per the existing Pressure Maintenance Agreement (PMA), National Grid is required to provide gas at a minimum pressure of 42.5 barg at Moffat for flows up to 26 mscmd. They have also advised a higher Anticipated Normal Off-take Pressure (ANOP) for Moffat of 47 barg (i.e. the expected pressure under normal circumstances). The ANOP pressure has been used in the network modelling. This ANOP pressure is assumed to reduce to 45 barg from 2015/16, which reduces the technical capacity of the Moffat Entry Point (Please refer to section 6.5.3 for further detail).

A minimum pressure of 30 barg is provided at Inch, and the Corrib Operator is required to provide up to 85 barg at Bellanaboy. No contractual arrangements have been finalised with Shannon LNG, but it is assumed that should the project proceed, they will be able to deliver up to the Maximum Operating Pressure (MOP) of the Ring-Main.

Glossary

AC	-	Alternating Current
AGI	-	Above Ground Installation
ANOP	-	Anticipated Normal Operating Pressure
AQ	-	Annual Quantity
BGN	-	Bord Gais Networks
BGÉ	-	Bord Gais Éireann
BPGM	-	BP Gas Marketing Limited
CAG	-	Common Arrangements for Gas
CAM	-	Capacity Allocation Mechanism
CBT	-	Customer Behaviour Trial
CCGT	-	Combined Cycle Gas Turbine
CDP	-	Cork to Dublin Pipeline
CER	-	Commission for Energy Regulation
CNG	-	Compressed Natural Gas
CP	-	Cathodic Protection
CS	-	Continental Shelf
DCVG	-	Differential Current Voltage Gradient surveys
DCENR	-	Dept of Communications, Energy and Natural Resources
DD	-	Degree Day
DM	-	Daily Metered
DRI	-	District Regulating Installation
DX	-	Distribution System
E/W	-	East/West (electricity interconnector)
EODQ	-	End of Day Quantity
ESD	-	EU Energy Services Directive
ESRI	-	Economic and Social Research Institute
GATG	-	Gas Advisory Task Group
GB	-	Great Britain
GCV	-	Gross Calorific Value
GDP	-	Gross Domestic Product
GICWP	-	Goatisland and Curraleigh West Pipeline
GTMS	-	Gas Transportation Management System
GWh	-	Giga-Watt hours
GWh/d	-	Giga-Watt hours per day
GWh/y	-	Giga-Watt hours per year
I/C	-	Industrial Commercial
IBP	-	Irish Balancing Point
IC	-	Interconnector
IHD	-	In Home Display
IOM	-	Isle of Man
I.T.	-	Information Technology
JGCS	-	Joint Gas Capacity Statement
kTOE	-	Kilotonne of Oil Equivalent
km	-	Kilometre
LDM	-	Large Daily Metered
LF	-	Load Factor
LNG	-	Liquefied Natural Gas
LSFO	-	Low Sulphur Fuel Oil
MEA	-	Manx Electricity Authority
MOP	-	Maximum Operating Pressure

mscm/d - Million standard cubic metres per day

MTR - Medium Term Review

MW - Mega Watts

NWP - North West Pipeline

NBP - National Balancing Point

NDM - Non - Daily Metered

NDS - Network Development Statement

NEC - Network Emergency Coordinator (in GB)

NEEAP - National Energy Efficiency Action Plan

NEM - Network Emergency Manager (in the ROI)

NGEM - Natural Gas Emergency Manager

NGEP - National Gas Emergency Plan

NGV - Natural Gas Vehicles

NI - Northern Ireland

NTS - National Transmission System (in GB)

OCGT - Open Cycle Gas Turbine

OI - Odour Intensity

P.A. - Per Annum

PMA - Pressure Maintenance Agreement

PR3 - Price Review 3

PSO - Public Service Obligation

PSE KEL - PSE Kinsale Energy Limited

PTL - Premier Transmission Ltd

PTTW - Pipeline to the West

QEC - Quarterly Economic Commentary

RES - Residential

ROI - Republic of Ireland

RTU - Remote Terminal Units

SCADA - Supervisory Control and Data Acquisition

SEI - Sustainable Energy Ireland

SEM - Single Electricity Market

SI - Statutory Instrument

SNIP - Scotland Northern Ireland Pipeline

SNP - South North Pipeline

SONI - System Operators Northern Ireland

SOS - Security of Supply

SRMC - Short Run Marginal Cost

SWL - South West Lobe

SWSOS - Southwest Scotland Onshore System

TFC - Total Final Consumption

TFEP - Task Force on Emergency Procedures

TPER - Total Primary Energy Requirement

TX - Transmission System

UK - United Kingdom

UREGNI - Northern Ireland Utility Regulator

UPS - Uninterrupted Power Supply

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Notes

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