Appendix One

Process Methodology

A1.1 Demand

The purpose of this section is to give a brief overview of the methodology that is adopted to develop forecasts of annual and peak demand. The methodology can be categorised into three main modelling areas; annual demand, demand/weather and peak demand modelling.

A1.1.1 Annual Demand Modelling

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

To gain a better understanding of how these assumptions are utilised and the modelling approach adopted it is necessary to consider the LDZ and NTS processes separately.

A1.1.1.1 LDZ Modelling

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

By adopting this approach we are able to take account of varying economic conditions and specific large loads within different LDZs.

A1.1.1.2 NTS Modelling

Historically, NTS demand (i.e. loads with their own connection to the NTS) was limited to a small number of large industrial sites and chemical works. However, with the advent of gas-fired power generation and interconnectors to Ireland and Continental Europe, a new methodology had to be developed. This methodology can best be described by looking at each sector in turn.

A1.1.1.3 Power Generation

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

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

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

The resultant power generation forecast, encompassing all fuel types, is then used to derive a split between gas-fired stations supplied by the NTS (or embedded within the DNs) and those with their own dedicated pipeline delivering supplies direct from the beach. There are currently five such stations, known as “Directs”, accounting for approximately 13% of total gas used for generation by UK major power producers in 2002.

A1.1.1.4 Exports

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

Exports to Ireland are derived from a sector based analysis of energy markets in Northern Ireland and the Republic of Ireland, including allowances for the depletion and development of indigenous gas-supplies, feedback from the TBE process, commercial sources and regulatory publications.

A1.1.1.5 Industrials

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

A1.1.2 Demand/Weather Modelling

In order to meet both the demand estimation requirements of the Network Code and planning requirements for forecasts of demand in future years, a consistent methodology for demand/weather modelling has been developed. Under this methodology, all demand models (whether for LDZ demand or for categories of NDM demand as required under the Network Code) are based on Composite Weather Variables (CWVs) defined and optimised for each LDZ. Details of the modelling approach, definitions of CWVs and current CWV parameters are provided in the document “NDM Profiling and Capacity Estimation Algorithms for 2002/3” (which is available to all Network Code signatories). Seasonal normal CWVs (one for each day and each LDZ) are produced in accordance with paragraph H1.5.2 of the Network Code, using a 71 year historical weather database.

All of our demand/weather modelling is based on a 71 year average condition as per Network Code, however, a set of annual demand forecasts is produced based on a warmer weather condition to make allowance for global warming. The annual demand data presented by this document includes such mild weather correction.

A1.1.3 Peak Day Demand Modelling

Once the annual demand forecasts and daily demand/weather models have been developed, a simulation methodology is employed, using historical weather data for each LDZ, to determine the peak day (in accordance with statutory/Licence obligations) and severe winter demand estimates. Where possible, the peak day demand of the NTS supplied loads, such as the power stations, are based on the contractual arrangements. Export demands are treated slightly differently; the European Interconnector is assumed not to be exporting at times of peak demand, due to the high price of British gas, and Irish demand is derived from the market-sector based approach mentioned above.

A1.2 Supply

A1.2.1 Process Introduction

Our 2003 forecasts continue to indicate a significant decline in production from the UKCS. Last year we presented a range of import dependency based on the extent of any UKCS upside. This year we present only a single view with a lower UKCS upside, the outcome is a UKCS decline broadly similar to that reported last year with an import dependency of 67% in 2012/13.

Compared with last year, there is now greater certainty regarding the anticipated location of new imports. Consequently, our supply scenarios are less extreme in terms of locational variation and are broadly based on proposed import projects rather than supply assumptions under which new imports were spread between St Fergus and Bacton. Though there is far greater certainty regarding the location of new imports, there still remains appreciable project uncertainty regarding timing and import volumes. Consequently we have developed two supply scenarios based on proposed import projects. The first is a Pipeline scenario, which gives weight to increased interconnectivity with Europe; the second places greater emphasis on LNG Importation. Both supply scenarios include pipeline imports and LNG imports, however they differ in the dominance of one type of project over the other. The true picture will probably lie somewhere between these two positions.

Feedback from our 2003 Transporting Britain's Energy consultation process was generally supportive of our assessment of supplies and the scenarios we presented to enable us to develop potential NTS investments. There was general agreement with our views of pending import dependency, although there were differences of opinion regarding the likely sources of this gas, notably the extent that LNG may feature.

Following on from last years concerns about information disclosure, when we received less detailed supply information through our consultation process, we are pleased to report a significant improvement in information received. This together with information derived from other commercially available sources, enables us to construct a 'match' of supplies to demand for each year of the next ten years. The match shows the assumed locations of supply, against the forecast level of demand at each of the key points on our network.

A1.3 NTS Capacity Planning

Using the supply/demand match as an input, we use a computer software package, FALCON, to analyse the performance of the transportation system. FALCON identifies the location of potential network capacity constraints and helps in the development of suitable reinforcement options that ensure the appropriate level of system security is maintained.

Having identified potential constraints on the system, we evaluate options for adding capacity to the network that represent a safe, economic and efficient solution, whilst maintaining system security. The options available to us to increase capacity include:

- Uprating pipeline operating pressures.
- Constructing new pipelines or storage.
- Uprating or modifying existing compressors or installing new compressor stations.
- Building additional regulators and offtakes.

This is an iterative process. The aim is to produce a robust system consistent with all the drivers for investment: provision of 1 in 20 peak day capacity (in accordance with Licence obligations); flexibility to provide close to peak entry capacity throughout the year, responding to signals for additional entry or exit capacity from industry players, and reducing the level of environmental emissions.

A1.4 Lower Pressure Tier Planning

Although the development of DN's Local Transmission Systems (LTS) is largely demand-led, LTS capacity planning processes are not dissimilar to those utilised for the development of the NTS. DNs use forecast demand to model system flow patterns and produce capacity plans that take account of anticipated changes in system load and within-day demand profiles.

The options available to relieve LTS capacity constraints include:

- Uprating pipeline operating pressures.
- Constructing new pipelines or storage.
- Constructing new supplies (offtakes from the NTS), regulators and control systems.

As well as planning to ensure that LTS pipelines are designed to the correct size to meet peak flows, there is a requirement to plan to meet the variation in demand over a 24-hour period. Diurnal storage is used to satisfy these variations and may consist of gas held in linepack, low-pressure gasholders, high-pressure vessels and salt cavities.

A1.4.1 Lower Pressure Tier Planning (<7 bar)

The lower pressure tier system (distribution system) is designed to meet expected gas flows in any six-minute period assuming reasonable diversity of demand. Lower tier reinforcement planning is based on LDZ peak demand forecasts, adjusted to take account of the characteristics of specific networks.

Network analysis is carried out using a suite of planning tools with the results being validated against a comprehensive set of actual pressure recordings. The planned networks are then used to assess future system performance to predict reinforcement requirements and the effects of additional loads. Reinforcement options are then identified, costed and programmed for completion before the constraint causes difficulties within the network. Reinforcement is usually carried out by installing a new main or by taking a new offtake point from a higher-pressure tier. In general, the reinforcement project is of such a size that the work can be completed and operational before the following winter.

A1.5 Investment Procedures and Project Management

All investment projects must comply with our Investment and Disposals Guidelines, which set out the broad principles that should be followed when evaluating high value investment or divestment projects. These guidelines are supported by specific guidelines for the UK Transmission and Distribution businesses.

The investment guidelines define the methodology to be followed for undertaking individual investments in a consistent and easy to understand manner. Together with the planning and budgeting methodology, they are used to ensure maximum value is obtained. For non-mandatory projects, the key investment focus in the majority of cases is to undertake only those projects that carry an economic benefit. For mandatory projects, such as safety-related work, the focus is on minimising the net present cost whilst not undermining the project objectives or the safety or reliability of the network.

The successful management of major investment projects is central to our business objectives. Our project management strategy involves:

- Determining the level of financial commitment and appropriate method of funding for the project.
- Monitoring and controlling the progress of the project to ensure that financial and technical performance targets are achieved.
- Post project and post investment review to ensure compliance and capture lessons learnt.

When a Transmission project is approved, a multi-discipline team prepares an Invitation to Tender in accordance with the EC Utilities Directive. For major projects, specialist consultants with experience of preparing and evaluating tender documents are used.

Tenders are received and evaluated against previously agreed technical, quality, safety, financial and programme criteria. They are compared on a cost basis with a database of capital projects. An award is then made to the most economically advantageous tender consistent with these criteria.

The successful contractor completes the project in accordance with an agreed programme of works. It remains the contractor’s responsibility to manage and supervise the works. We monitor the work on a day-to-day basis and manage the funding of the project by careful cost control. Following completion, a Post Completion Review is carried out to provide feedback to management on project performance and to improve future decision making processes.

Our project management of major investment projects is designed to ensure that they are delivered on time, to the appropriate quality standards at minimum cost. The project management process in particular makes use of professional consultants and specialist contractors, all of who are appointed subject to competitive tender.

Appendix Two

Gas Demand & Supply Volume Forecasts

A2.1 Demand

TABLE A2.1A – Forecast Annual Demand – Split by LDZ & NTS Load Categories (TWh)

Calendar Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
0 to 73MWh	415	422	425	429	433	438	440	444	447	452
73 to 732MWh	63	65	65	66	67	68	69	71	72	73
732 to 5860MWh	54	55	56	57	58	59	59	60	62	63
Total Small User	533	541	546	552	558	566	569	575	580	589
Firm 5860MWh - 1465GWh	72	74	76	80	84	88	90	93	95	97
Interruptible <1465GWh	93	94	97	100	101	104	105	106	108	110
Total Large User	165	168	173	180	185	192	195	198	203	208
LDZ Very Large User	35	37	38	38	38	38	41	42	47	50
Total LDZ	733	746	757	770	780	796	805	815	830	847
NTS Power Generation	226	239	254	264	273	286	294	302	305	307
NTS Industrials	36	36	36	37	38	39	40	41	43	46
Exports via Moffat	59	59	60	71	75	64	54	61	67	76
Exports via IUK	133	125	110	74	73	73	73	72	72	75
Total NTS	454	459	461	446	458	462	461	476	488	504
Total Formula Volumes	1187	1205	1217	1216	1238	1258	1266	1291	1318	1351
Shrinkage	15	15	15	17	17	18	18	18	19	19
Total Throughput	1202	1220	1233	1233	1256	1276	1284	1310	1337	1370

Gas Supply Year	2003/4	2004/5	2005/6	2006/7	2007/8	2008/9	2009/10	2010/11	2011/12	2012/13
Total Throughput	1210	1231	1232	1249	1272	1280	1303	1329	1362	1383

Notes

- *Volumes are based on weather data from the 35 years up to 2000.*
- *NTS Power Generation includes all large-scale gas-fired plants connected to the NTS but excludes the consumption of those stations supplied by third party pipelines and those embedded within DNs.*
- *Figures may not sum exactly due to rounding.*

FIGURE A2.1A – Forecast Annual Demand

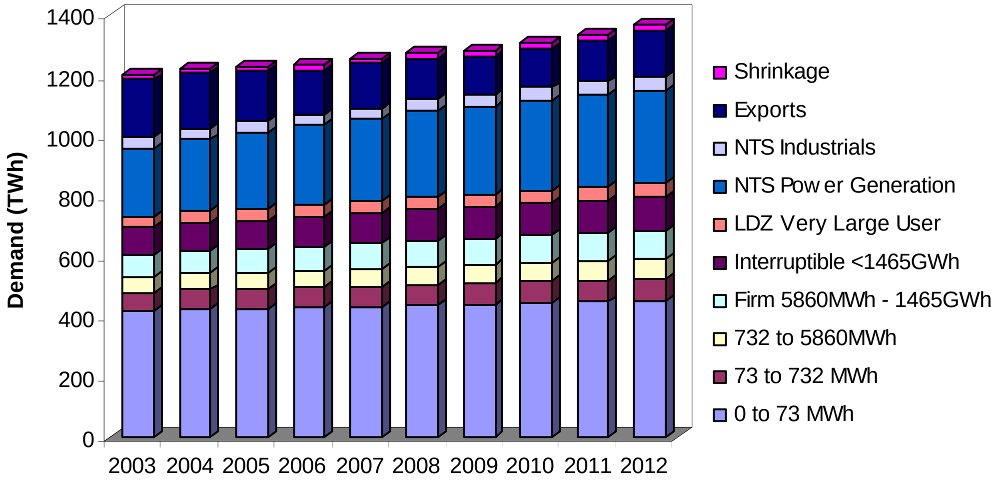


TABLE A2.1B – Forecast LDZ Annual Demands – Split by Supply Type (TWh)

LDZ	Load Category	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Scotland	Firm	51	52	53	54	55	56	56	57	58	59
	Int	13	13	14	14	14	15	15	15	15	16
	Total	64	65	67	68	69	71	71	72	73	75
Northern	Firm	36	37	37	38	38	39	40	40	41	41
	Int	10	10	10	10	10	10	10	10	11	11
	Total	46	47	47	48	48	49	50	50	52	52
North West	Firm	76	77	78	79	81	82	82	83	84	85
	Int	15	15	16	16	16	16	17	17	17	18
	Total	91	92	94	95	97	98	99	100	101	103
North Eastern	Firm	41	42	42	43	43	44	44	45	46	46
	Int	9	9	9	9	10	10	10	10	11	11
	Total	50	51	51	52	53	54	54	55	57	57
East Mids.	Firm	65	66	66	67	68	69	70	71	72	73
	Int	17	17	18	18	18	19	20	20	24	25
	Total	82	83	84	85	86	88	90	91	96	98
West Mids.	Firm	59	60	61	62	63	64	65	66	66	67
	Int	6	6	6	6	6	6	6	6	6	7
	Total	65	66	67	68	69	70	71	72	72	74
Wales (Nth & Sth)	Firm	31	32	33	34	34	35	35	35	36	37
	Int	12	12	12	12	13	13	13	13	13	14
	Total	43	44	45	46	47	48	48	48	49	51
Eastern	Firm	47	48	48	49	50	51	51	52	53	54
	Int	7	6	7	7	7	7	7	7	7	7
	Total	54	54	55	56	57	58	58	59	60	61
North Thames	Firm	65	66	66	67	68	70	70	71	72	73
	Int	8	8	8	8	8	8	8	8	9	9
	Total	73	74	74	75	76	78	78	79	81	82
South East	Firm	69	70	70	71	71	72	72	72	73	74
	Int	9	9	9	10	10	11	12	12	13	15
	Total	78	79	79	81	81	83	84	84	86	89
Southern	Firm	43	44	45	46	47	48	49	49	50	51
	Int	7	7	8	8	8	8	8	8	8	9
	Total	50	51	53	54	55	56	57	57	58	60
South West	Firm	34	34	35	35	36	37	37	38	40	41
	Int	5	5	5	6	6	6	6	6	6	6
	Total	39	39	40	41	42	43	43	44	46	47
LDZ Total	**Firm**	**615**	**629**	**635**	**646**	**654**	**667**	**673**	**682**	**690**	**699**
	Int	**118**	**117**	**122**	**124**	**126**	**129**	**132**	**133**	**140**	**148**
	Total	**733**	**746**	**757**	**770**	**780**	**796**	**805**	**815**	**830**	**847**

Notes

- *Volumes are based on weather data from the 35 years up to 2000.*
- *LDZ Annual Demands refer to forecast consumption and exclude shrinkage.*
- *The LDZs are consistent with the Network Code and are defined in Appendix 4.*

TABLE A2.1C – Forecast Network Annual Demands – Split by Supply Type (TWh)

LDZ	**Load Category**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Scotland	Firm	51	52	53	54	55	56	56	57	58	59
	Int	13	13	14	14	14	15	15	15	15	16
	Total	64	65	67	68	69	71	71	72	73	75
North of England	Firm	77	79	79	81	81	83	84	85	87	87
	Int	19	19	19	19	20	20	20	20	22	22
	Total	96	98	98	100	101	103	104	105	109	109
North West	Firm	76	77	78	79	81	82	82	83	84	85
	Int	15	15	16	16	16	16	17	17	17	18
	Total	91	92	94	95	97	98	99	100	101	103
East of England	Firm	112	114	114	116	118	120	121	123	125	127
	Int	24	23	25	25	25	26	27	27	31	32
	Total	136	137	139	141	143	146	148	150	156	159
West Midlands	Firm	59	60	61	62	63	64	65	66	66	67
	Int	6	6	6	6	6	6	6	6	6	7
	Total	65	66	67	68	69	70	71	72	72	74
Wales and the West	Firm	65	66	68	69	70	72	72	73	76	78
	Int	17	17	17	18	19	19	19	19	19	20
	Total	82	83	85	87	89	91	91	92	95	98
South of England	Firm	112	114	115	117	118	120	121	121	123	125
	Int	16	16	17	18	18	19	20	20	21	24
	Total	128	130	132	135	136	139	141	141	144	149
London	Firm	65	66	66	67	68	70	70	71	72	73
	Int	8	8	8	8	8	8	8	8	9	9
	Total	73	74	74	75	76	78	78	79	81	82
Network Total	**Firm**	**615**	**629**	**635**	**646**	**654**	**667**	**673**	**682**	**690**	**699**
	Int	**118**	**117**	**122**	**124**	**126**	**129**	**132**	**133**	**140**	**148**
	Total	**733**	**746**	**757**	**770**	**780**	**796**	**805**	**815**	**830**	**847**

Notes

- *Volumes are based on weather data from the 35 years up to 2000.*
- *Network Annual Demands refer to forecast consumption and exclude shrinkage*

TABLE A2.1D - Forecast 1 in 20 Peak Day Firm Demand by LDZ & NTS (GWh per day)

LDZ	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Scotland	341	347	354	361	368	374	379	385	390	396	403
Northern	264	267	271	275	278	283	286	290	293	297	301
North West	525	532	537	550	555	561	567	571	576	581	587
North East	275	278	283	287	290	293	296	300	303	307	312
East Midlands	453	459	465	472	479	485	491	497	504	510	518
West Midlands	454	458	464	471	476	484	489	494	500	506	513
Wales (North & South)	238	241	244	248	251	254	257	259	262	266	270
Eastern	358	363	368	374	379	385	390	395	399	404	411
North Thames	492	495	499	504	511	518	522	526	532	536	542
South East	505	510	513	522	525	528	531	534	536	539	544
Southern	371	376	383	392	400	405	410	415	420	425	432
South West	270	274	278	283	287	291	295	301	311	315	319
LDZ Total	**4546**	**4600**	**4660**	**4738**	**4798**	**4860**	**4912**	**4967**	**5027**	**5082**	**5152**
NTS Total	**1192**	**1222**	**1274**	**1321**	**1385**	**1481**	**1423**	**1502**	**1518**	**1561**	**1601**
Total	**5737**	**5821**	**5934**	**6058**	**6183**	**6341**	**6335**	**6470**	**6545**	**6643**	**6753**

Notes

- *Peak day data is presented on a gas supply year basis.*
- *The LDZs are consistent with the Network Code and are defined in Appendix 4.*
- *NTS and LDZ figures include shrinkage.*
- *NTS Total Peak Day demand excludes Continental Interconnector flows as it assumed that gas will be flowing into the UK during periods of high demand.*
- *Figures may not sum exactly due to rounding.*

FIGURE A2.1D - Forecast 1 in 20 Peak Day Firm Demand

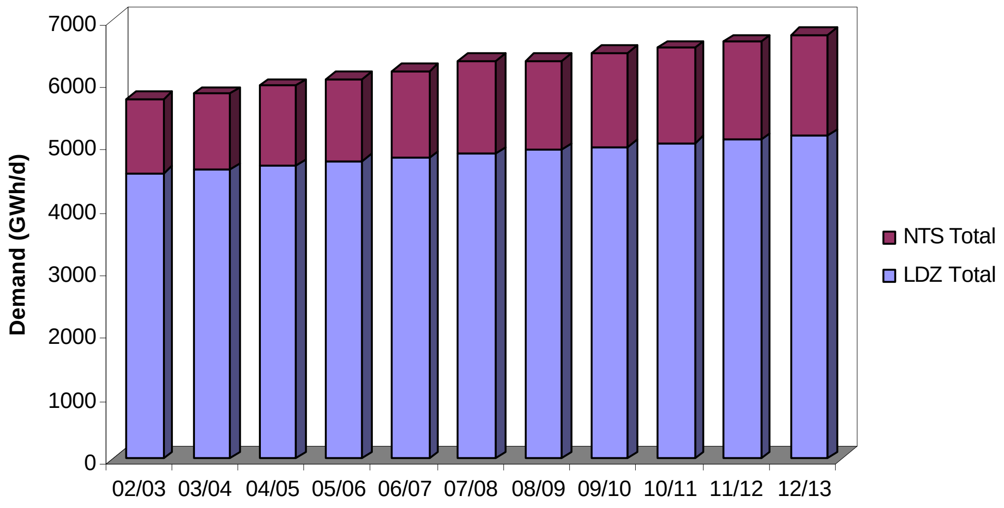
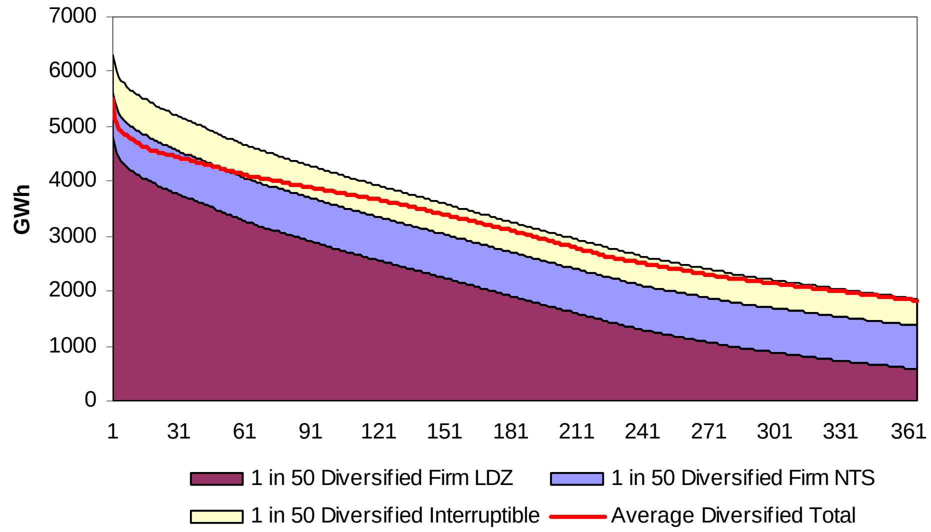


FIGURE A2.1E – 2005/6 Load Duration Curve



Notes

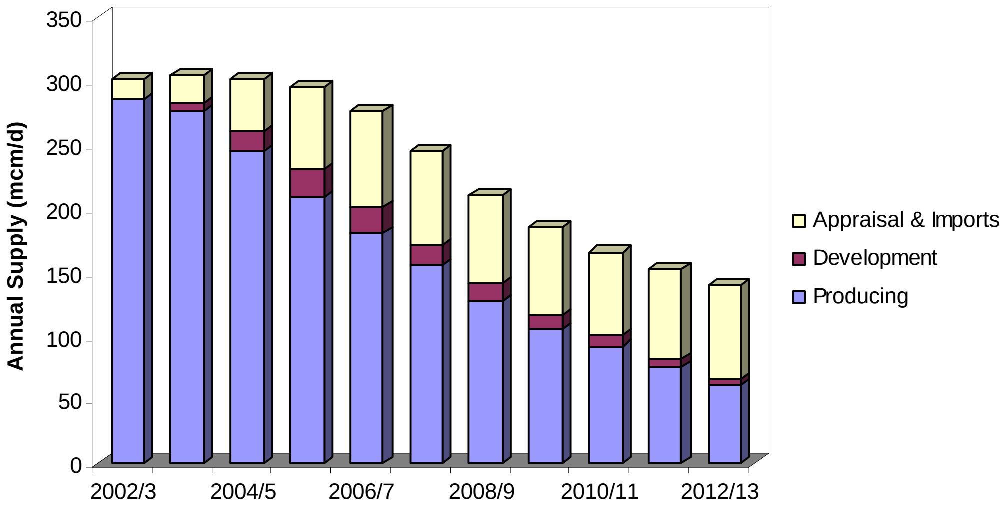
- *Severe 1 in 50 Load Duration Curve, as defined in the Glossary*
- *Average Load Duration Curve is based on weather data from the 35 years up to 2000, with the area under the curve being consistent with the annual demands shown in table A2.1A*

A2.2 Annual Supply Data Available to Transco

TABLE A2.2A - Annual Supplies – Information Received by Supply Category (mcm/d)

	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Producing	286	276	244	209	181	155	128	106	92	76	61
Development	0	6	16	22	20	17	13	11	9	6	5
Appraisal & Imports	15	23	41	64	75	73	70	69	65	71	74

FIGURE A2.2A - Annual Supplies - Information Received by Supply Category (mcm/d)



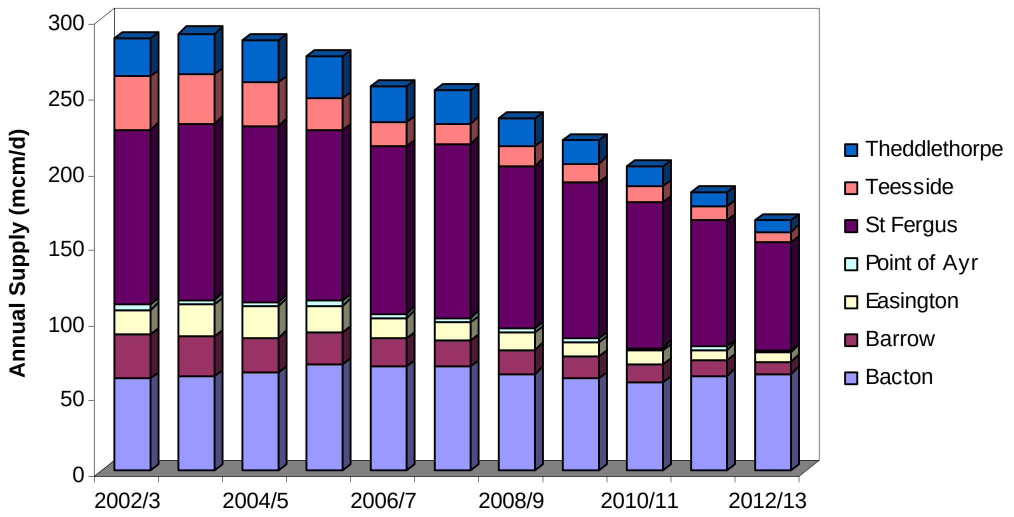
Notes

- *Imports include existing Norwegian flows and Interconnector imports.*

TABLE A2.2B - Annual Supplies – Data Available by Supply Terminal (mcm/d)

	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Bacton	61	63	65	71	69	70	65	62	59	63	65
Barrow	30	26	24	21	19	17	16	14	12	10	8
Easington	16	21	21	18	14	12	11	10	9	8	6
Point of Ayr	4	3	3	3	3	3	3	2	2	2	1
St Fergus	117	117	117	113	111	116	109	104	97	84	72
Teesside	35	33	28	21	16	13	13	13	11	9	8
Theddlethorpe	25	27	28	28	24	22	18	16	13	10	7

FIGURE A2.2B - Annual Supplies - Data Available by Supply Terminal (mcm/d)



Notes

- *Bacton volumes include Interconnector Imports.*
- *St Fergus volumes include existing Norwegian imports*

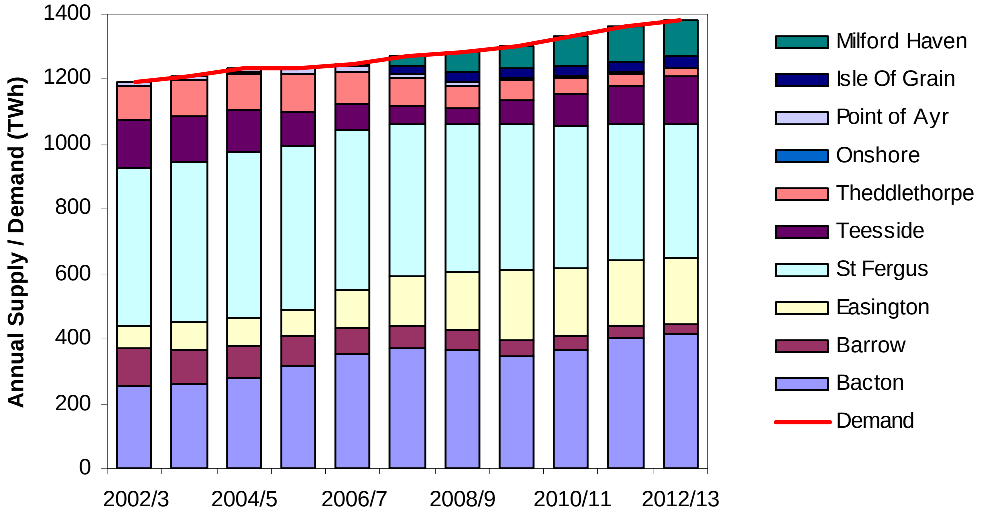
A2.3 Annual Supply Scenarios

A2.3.1 Annual Demand & Pipeline Supply Scenario

TABLE A2.3A – Annual Demand & Pipeline Supply Scenario (TWh)

	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Demand	1192	1210	1231	1232	1249	1272	1280	1303	1329	1362	1383
Bacton	253	261	279	314	351	368	362	343	364	400	412
Barrow	117	105	98	91	80	68	63	53	44	37	32
Easington	66	85	88	80	118	155	183	215	209	203	206
St Fergus	489	494	511	511	495	471	454	447	437	418	413
Teesside	150	141	126	100	76	56	49	77	99	120	147
Theddlethorpe	100	108	116	121	101	85	70	59	47	36	22
Onshore	1	1	1	1	1	0	0	0	0	0	0
Point of Ayr	15	14	12	14	14	12	9	8	8	6	3
Isle of Grain	0	0	0	0	12	22	34	33	33	33	34
Milford Haven	0	0	0	0	0	34	57	67	88	109	114
Total	**1192**	**1210**	**1231**	**1232**	**1249**	**1272**	**1280**	**1303**	**1329**	**1362**	**1383**

FIGURE A2.3A – Annual Demand & Pipeline Supply Scenario (TWh)



Notes

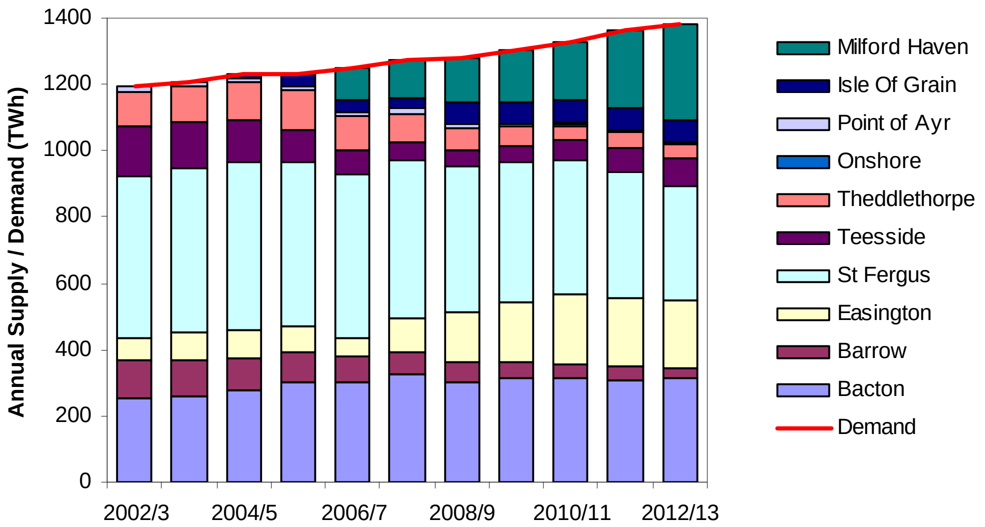
- *Bacton volumes include Interconnector imports.*
- *Figures may not sum exactly due to rounding.*

A2.3.2 Annual Demand & LNG Supply Scenario

TABLE A2.3B – Annual Demand & LNG Supply Scenario (TWh)

	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Demand	1192	1210	1231	1232	1249	1272	1280	1303	1329	1362	1383
Bacton	253	261	276	304	301	325	302	311	313	310	312
Barrow	117	105	97	88	79	68	61	53	44	38	32
Easington	66	85	87	77	57	103	148	177	211	208	204
St Fergus	489	494	506	497	491	474	443	423	401	376	346
Teesside	150	141	125	97	75	56	48	49	60	72	83
Theddlethorpe	100	108	115	118	100	86	69	59	48	48	44
Onshore	1	1	1	1	1	0	0	0	0	0	0
Point of Ayr	15	14	12	13	14	12	11	8	8	6	3
Isle of Grain	0	0	12	36	36	34	66	67	67	67	67
Milford Haven	0	0	0	0	96	112	133	156	177	235	292
Total	**1192**	**1210**	**1231**	**1232**	**1249**	**1272**	**1280**	**1303**	**1329**	**1362**	**1383**

FIGURE A2.3B – Annual Demand & LNG Supply Scenario (TWh)



Notes

- *Bacton volumes include Interconnector imports.*
- *Figures may not sum exactly due to rounding.*

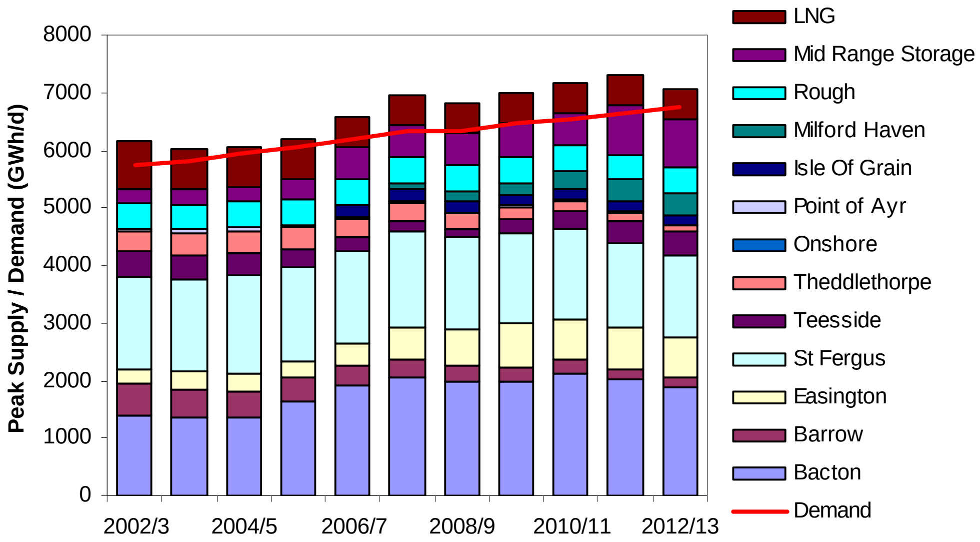
A2.4 Peak Supply Scenarios

A2.4.1 Peak Demand & Pipeline Supply Scenario

TABLE A2.4A – Peak Demand & Pipeline Scenario (GWh per day)

	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Demand	5737	5821	5934	6058	6183	6341	6335	6470	6545	6643	6753
Bacton	1382	1354	1344	1642	1903	2047	1971	1980	2126	2010	1882
Barrow	558	498	448	400	361	331	298	261	222	190	162
Easington	242	319	317	278	389	542	626	741	728	712	693
St Fergus	1597	1588	1715	1651	1593	1658	1579	1564	1552	1483	1421
Teesside	449	420	388	297	228	196	168	254	319	384	447
Theddlethorpe	357	383	387	387	321	301	246	208	170	130	77
Onshore	3	3	3	2	1	1	1	1	1	0	0
Point of Ayr	47	47	47	47	47	47	26	23	25	20	8
Isle of Grain	0	0	0	0	190	190	190	190	190	190	190
Milford Haven	0	0	0	0	0	109	181	217	290	362	362
Rough	448	448	448	448	448	448	448	448	448	448	448
Mid Range Storage	254	254	254	335	569	569	569	569	569	839	839
LNG	826	712	712	712	525	525	525	525	525	525	525
Total	**6164**	**6026**	**6062**	**6198**	**6575**	**6964**	**6829**	**6981**	**7165**	**7294**	**7054**

FIGURE A2.4A – Peak Demand & Pipeline Scenario (GWh per day)



Notes

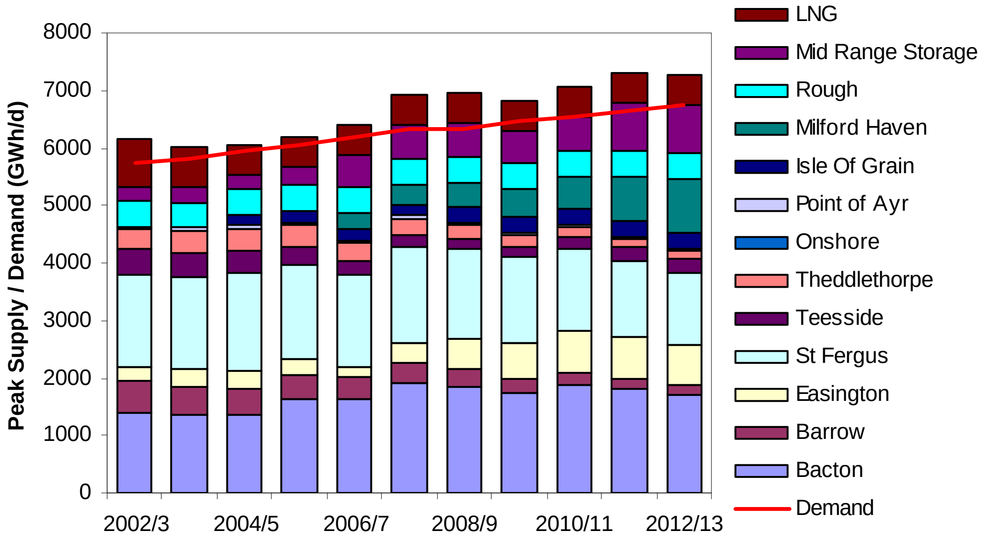
- *Bacton volumes include Interconnector imports.*
- *Figures may not sum exactly due to rounding.*

A2.4.2 Peak Demand & LNG Supply Scenario

TABLE A2.4B – Peak Demand & LNG Supply Scenario (GWh per day)

	02/03	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13
Demand	5737	5821	5934	6058	6183	6341	6335	6470	6545	6643	6753
Bacton	1382	1354	1344	1642	1642	1922	1845	1729	1875	1795	1720
Barrow	558	498	448	400	361	331	298	261	222	190	162
Easington	242	319	317	278	201	366	520	614	728	712	693
St Fergus	1597	1588	1715	1651	1593	1658	1579	1503	1435	1332	1237
Teesside	449	420	388	297	228	196	168	170	202	233	262
Theddlethorpe	357	383	387	387	321	301	246	208	170	166	149
Onshore	3	3	3	2	1	1	1	1	1	0	0
Point of Ayr	47	47	47	47	47	47	35	23	25	20	8
Isle of Grain	0	0	190	190	190	190	275	275	275	275	275
Milford Haven	0	0	0	0	290	362	435	507	580	761	942
Rough	448	448	448	448	448	448	448	448	448	448	448
Mid Range Storage	254	254	254	335	569	569	569	569	569	839	839
LNG	826	712	525	525	525	525	525	525	525	525	525
Total	**6164**	**6026**	**6065**	**6201**	**6416**	**6915**	**6946**	**6834**	**7054**	**7297**	**7261**

FIGURE A2.4B – Peak Demand & LNG Supply Scenario (GWh per day)



Notes

- *Bacton volumes include Interconnector imports.*
- *Figures may not sum exactly due to rounding.*

Appendix Three

Actual Flows 2002

This Appendix describes annual and peak flows during the calendar year 2002. Where relevant, more up to date data from the subsequent winter period has been included to give gas supply year figures.

A3.1 Annual Flows

Annual forecasts are based on average weather conditions. Therefore, when comparing actual demand with forecasts, demand has been adjusted to take account of the difference between the actual weather and the seasonal normal weather. The result of this calculation is the weather corrected demand.

Over the last decade the UK has seen some of the warmest winters on record and consequently, we have adjusted the long term average weather condition to allow for global warming. Hence both the weather corrected actual and forecast demands are shown assuming a weather condition based on weather data from the 35 years up to 2000.

Actual demands incorporate a reallocation of demand between 0 to 73MWh and >73MWh firm load bands to allow for reconciliation, loads crossing between thresholds, etc. Consequently, the load band splits of the actual and corrected demands & forecasts shown in Table A3.1 are slightly different from those incorporated in the Transco Accounts.

Table A3.1 provides a comparison of actual and weather corrected demands during the 2002 calendar year with the forecasts presented in the 2002 Ten Year Statement. Annual demands are presented in the format of LDZ and NTS load bands/categories, consistent with the basis of system designed and operation.

TABLE A3.1 – Annual Demand for 2002 (TWh) – LDZ / NTS Split

TWh	**Actual Demand**	**Weather Corrected Demand**	**2002 10 YS Forecast Demand**
0-73 MWh	381	411	409
73-732 MWh	58	63	61
>732 MWh Firm	138	142	144
Interruptible	110	111	111
LDZ Total	687	727	725
Industrial	33	33	31
Power Generation	228	229	219
Exports	158	158	169
NTS Loads	419	420	418
Total Consumption	1106	1147	1143
Shrinkage	14	15	15
Total Throughput	**1120**	**1162**	**1158**

Table A3.1 indicates that the weather was warmer than normal reducing total throughput by 42TWh (3.6%). Growth in LDZ demand was in line with expectations with a small over forecast in the industrial firm sector (>732MWh) being offset by marginally higher than expected growth in the domestic (0 to73MWh) and commercial (73 to 732MWh) sectors.

Demand from loads connected directly to the NTS was also in line with expectations with higher growth in the Power Generation sector being offset by lower exports.

Total weather corrected demand grew by 3.5% during 2002, this compares favourably to the previous year's increase of only 0.3%, but is lower than the annual increases experienced in 2000 and 1999, 9% and 13% respectively.

A3.2 Compressor Usage

Table A3.2 shows the gas used at each of the compressor stations during the gas year 2002/3. It also shows the maximum fuel usage day for the 8th January 2003, the day of the highest level of supplies to the NTS.

TABLE A3.2 – Compressor Usage for Gas Year 2002/3 (mcm)

Compressor	Total 2002/3	Compressor Use on Max. Supply Day - 08/01/03
Aberdeen	65.36	0.21
Alrewas	23.50	0.02
Aylesbury	2.01	0.05
Bathgate	58.22	0.18
Bishop Auckland	52.36	0.12
Cambridge	0.65	0.00
Carnforth	57.03	0.18
Chelmsford	3.67	0.06
Churchover	15.21	0.15
Diss	10.77	0.11
Hatton	61.75	0.28
Huntingdon	24.73	0.22
Kings Lynn	9.45	0.11
Kirriemuir	68.06	0.23
Moffat	48.40	0.14
Nether Kellett	0.00	0.00
Peterborough	17.12	0.21
Scunthorpe	25.19	0.08
St Fergus	122.51	0.42
Warrington	42.17	0.15
Wisbech	1.72	0.09
Wooler	19.34	0.06
Wormington	2.40	0.07
Lockerley (electric)	N/A	N/A
Peterstow (electric)	N/A	N/A
Total	**731.60**	**3.13**

A3.3 Peak & Minimum Flows

A3.3.1 System Entry – Maximum Day Flows

The day of highest demand on the NTS, both for the winter 2002/3 and historically, was the 7th January 2003, when 450mcm/d was delivered via our system. The highest supply day, 452mcm/d, occurred the following day when system demand was slightly lower. The day of minimum supplies in 2002/3 was the 14th September 2003, when supplies were 190mcm/d.

TABLE A3.3A – System Entry – Maximum Supply Day Flows on 8th January 2003 (mcm/d)

Terminal	Maximum Day 8th Jan 2003	2002 Peak Forecast	Highest Daily for 2002/3
Bacton inc I/C	107.99	123.85	107.99
Barrow	49.30	52.40	50.20
Easington (exc. Rough)	22.19	21.78	24.60
Onshore	0.21	0.20	0.20
Point Of Ayr	4.16	2.82	5.20
St Fergus	133.83	135.39	140.00
Teesside	31.64	37.95	44.30
Theddlethorpe	24.01	34.11	32.60
Sub Total	373.35	408.49	405.1
Storage Withdrawal	78.61	122.19	78.61
Total	**451.96**	**530.68**	**483.71**

Notes

- *The maximum day for 2002/3 refers to flows on the 8th January 2003. These flows are not necessarily commensurate with current forecasts or with maximum flows of individual terminals.*
- *Peak forecast refers to the Northern Supply Scenario in the 2002 Ten Year Statement. Volumes are based on actual flow CVs.*
- *Bacton terminal flows include imports via the European Interconnector.*
- *Highest daily flows by terminal are non-concurrent and relate to the 2002/3 supply period.*
- *Figures may not sum exactly due to rounding.*

A3.3.2 System Entry – Minimum Day Flows

TABLE A3.3B – System Entry Flows on the Minimum Demand Day of Gas Year 2002/3 (mcm/d)

Terminal	**Minimum Day 14th Sept 2003**
Bacton inc I/C	46.65
Barrow	7.68
Easington (exc. Rough)	14.91
Onshore	0.19
Point Of Ayr	0.00
St Fergus	74.47
Teesside	21.69
Theddlethorpe	24.56
Sub Total	190.14
Storage Withdrawal	0.00
Total	190.14

A3.3.3 System Exit – Maximum and Peak Day Flows

Table A3.3C shows actual flows out of the NTS on the maximum demand day of gas year 2002/3 compared to the forecast peak flows.

TABLE A3.3C – NTS Exit Flows on 7th January 2003 (mcm)

LDZ	**Maximum Day 7th Jan 2003**	**1 in 20 Peak for 2002/3**
Scotland	29.30	31.85
Northern	18.99	23.99
North West	46.55	48.83
North East	22.75	25.57
East Midlands	30.82	41.63
West Midlands	33.03	42.09
Wales	20.33	21.88
Eastern	28.54	32.31
North Thames	38.13	45.97
South East	39.01	46.98
Southern	27.57	34.43
South West	21.52	25.11
LDZ Total	356.53	420.63
NTS Loads	92.49	117.69
Total	**449.02**	**538.32**

Notes

- *The maximum day for gas year 2002/3 refers to flows on the 7th January 2003. This was the overall highest demand day, but individual LDZs may have seen higher demands on other days.*
- *NTS actual loads include Irish interconnector demand.*
- *Due to linepack changes, there may be a small difference between total demand and total supply on the day.*
- *Figures may not sum exactly due to rounding.*

A3.3.4 System Exit – Minimum Day Flows

TABLE 3.3D – Actual NTS Exit Flows on the Minimum Demand Day of Gas Year 2002/3 (mcm/d)

LDZ	**Minimum Day 14th Sept 2003**
Scotland	7.18
Northern	5.13
North West	8.84
North East	5.77
East Midlands	9.40
West Midlands	5.80
Wales	5.58
Eastern	5.36
North Thames	7.21
South East	9.11
Southern	4.74
South West	3.45
LDZ Total	77.56
NTS Loads	110.35
Total	**187.91**

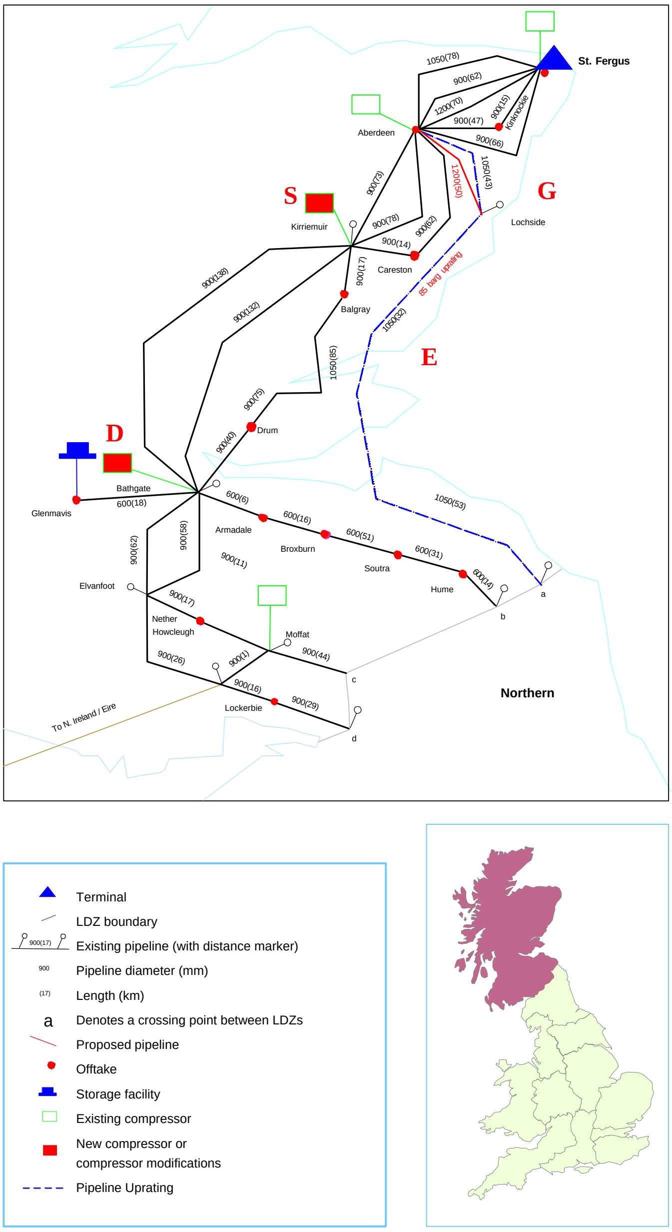
Notes

- *The minimum day for gas year 2002/3 refers to flows on the 14th September 2003. This was the overall lowest demand day, but individual LDZs may have seen lower demands on other days.*
- *NTS actual loads include Irish interconnector demand.*
- *Due to linepack changes, there is a small difference between total demand and total supply on the day.*
- *Figures may not sum exactly due to rounding.*

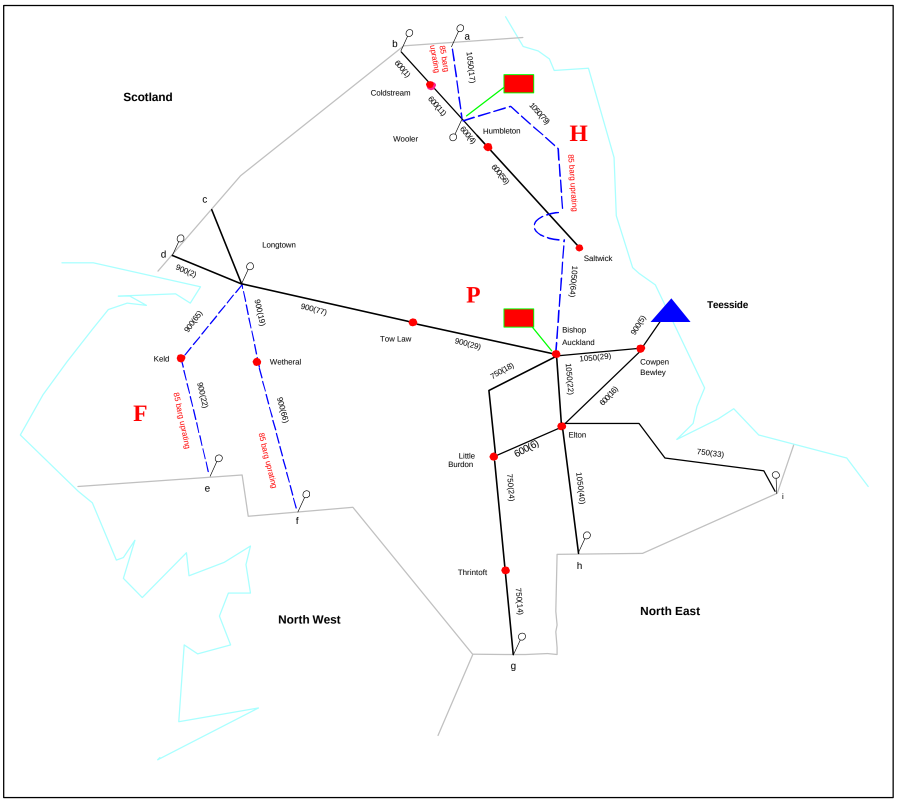
Appendix Four

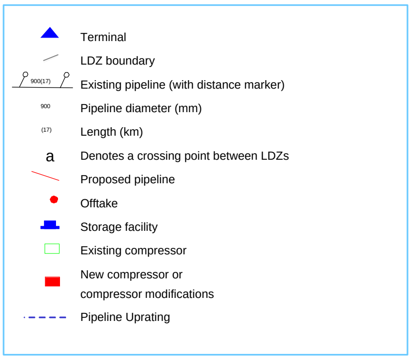
The Gas Transportation System

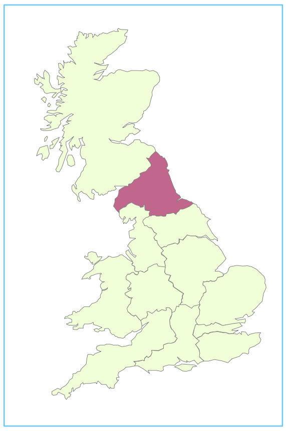
Scotland (SC) – NTS



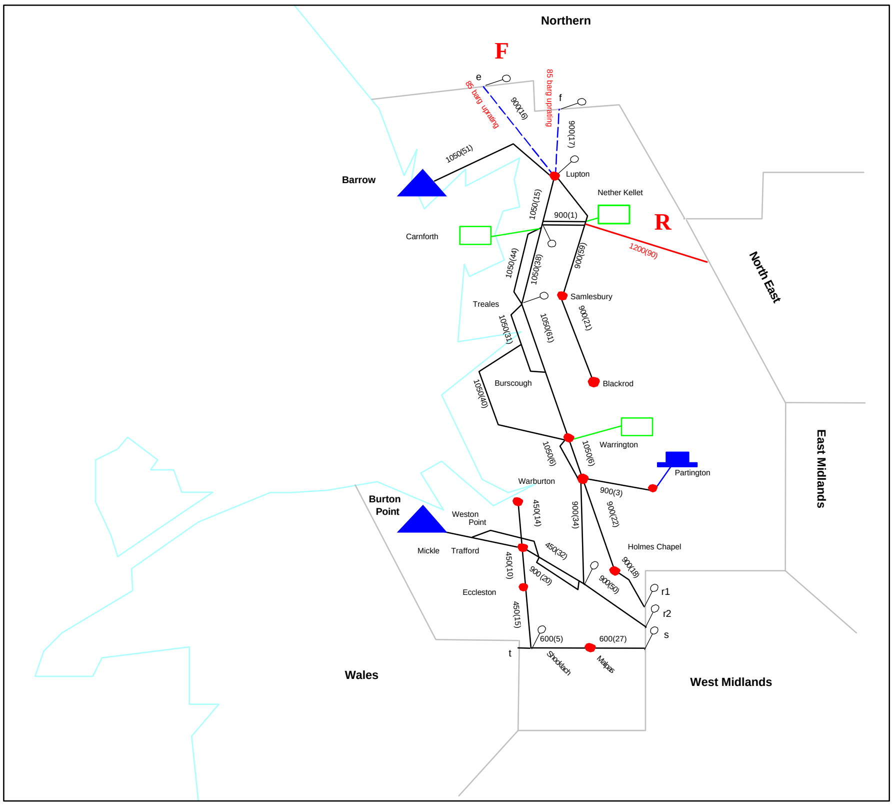
Northern (NO) – NTS

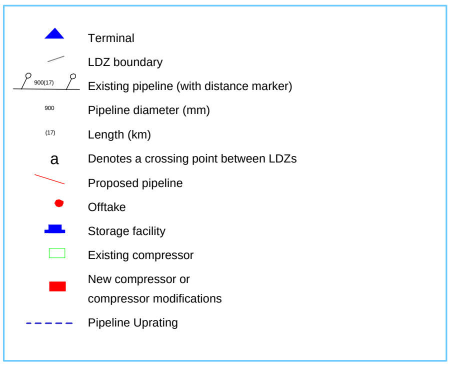


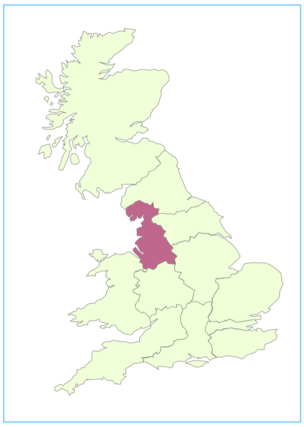




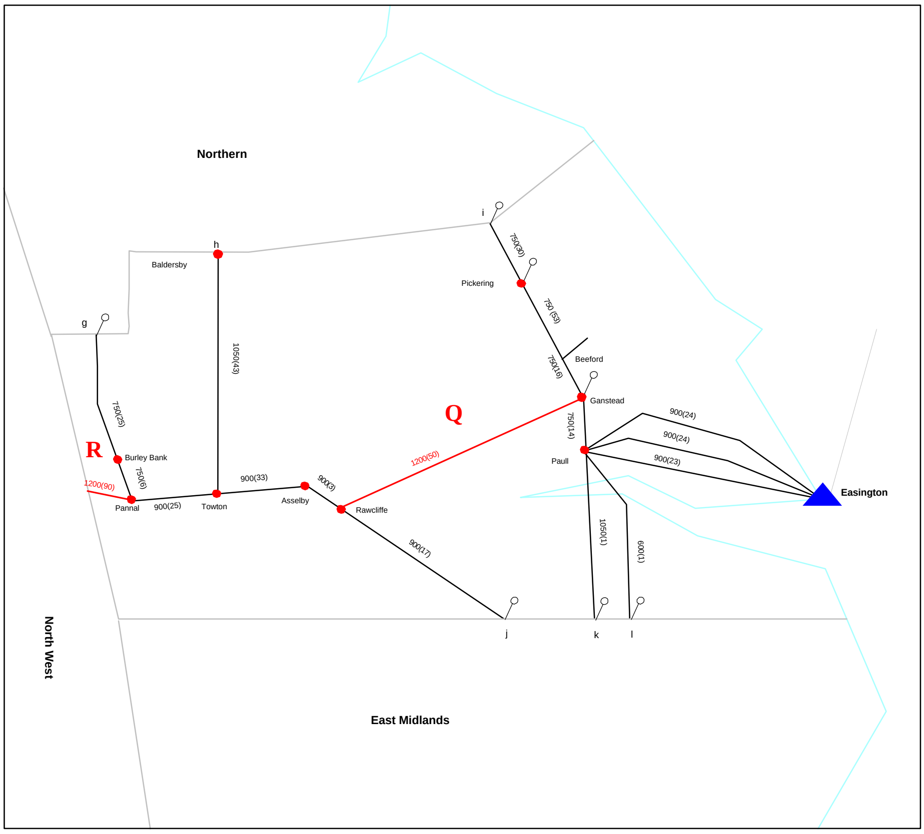
North West (NW) – NTS

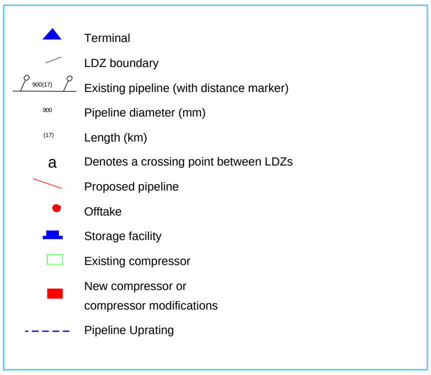


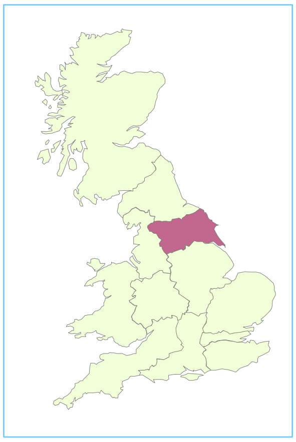




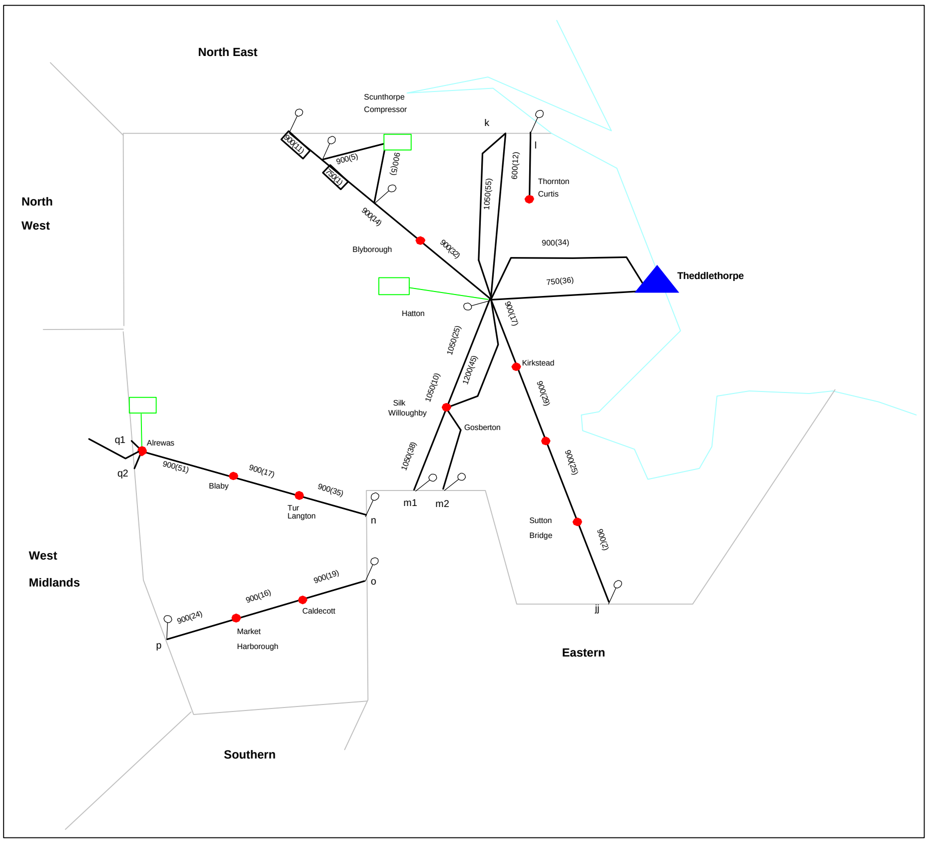
North East (NE) – NTS

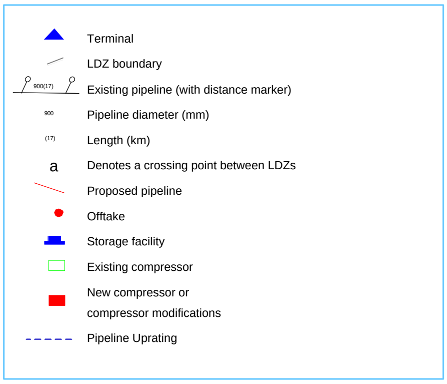


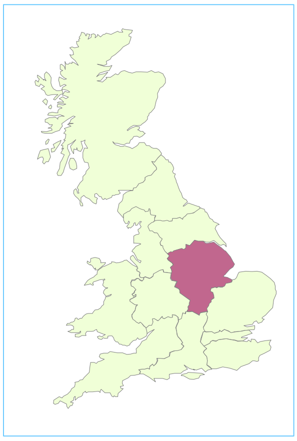




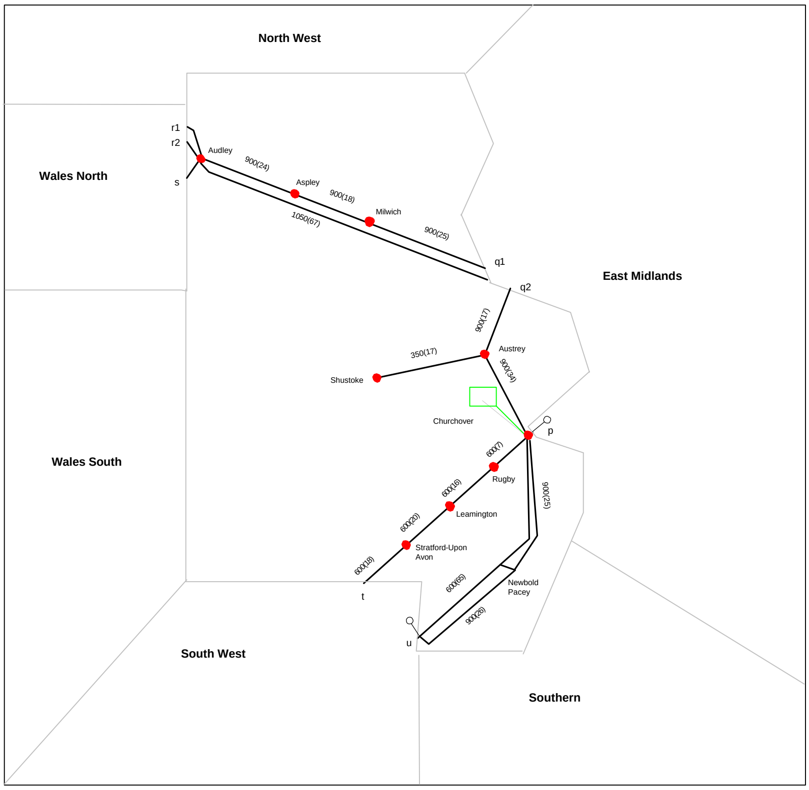
East Midlands (EM) – NTS

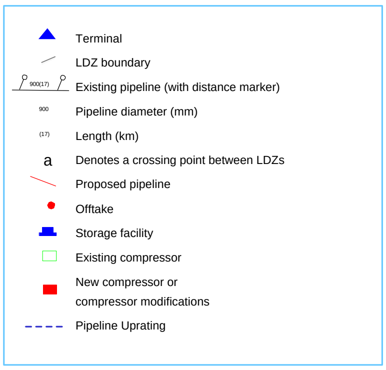


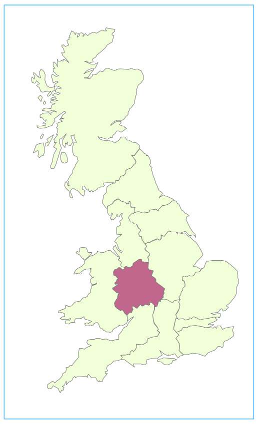




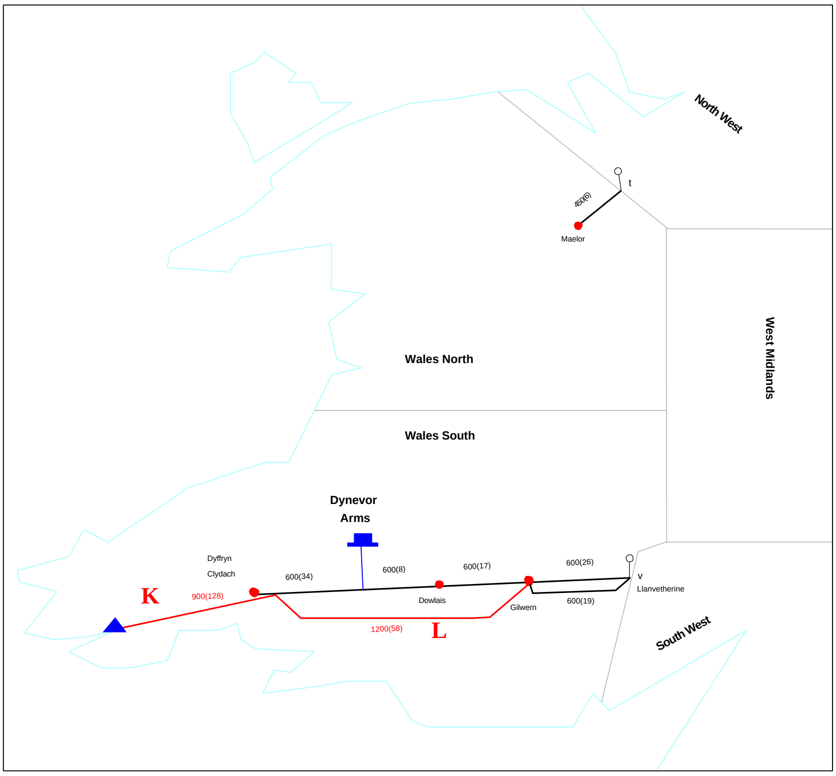
West Midlands (WM) – NTS

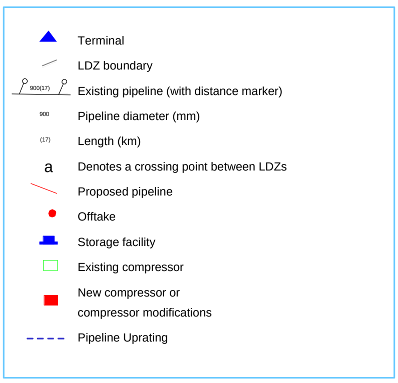


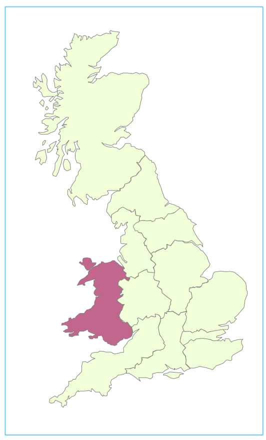




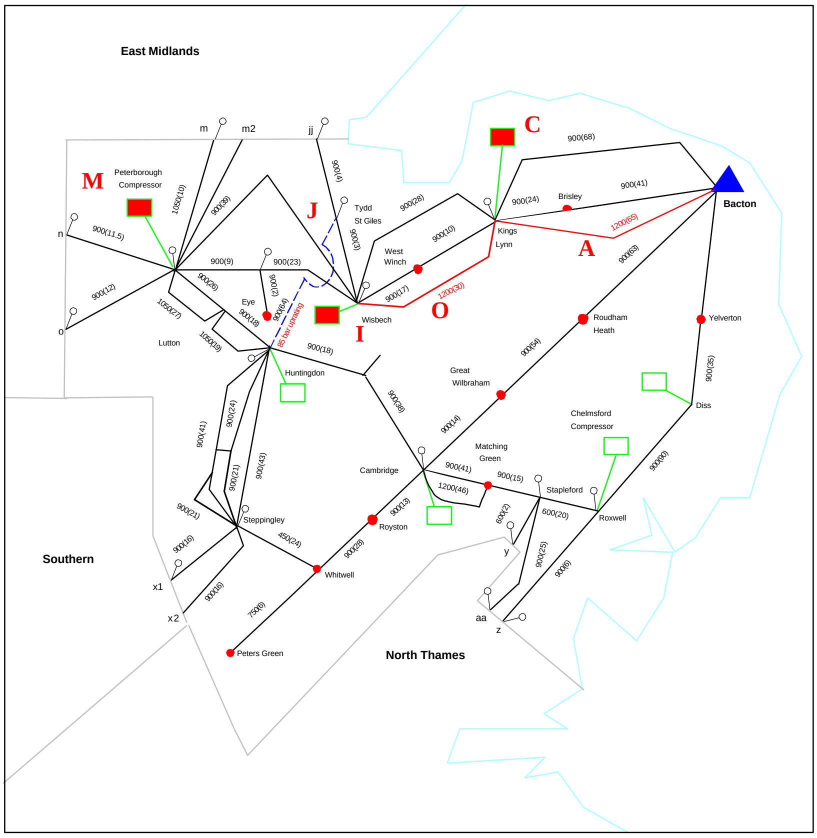
Wales (WN & WS) – NTS

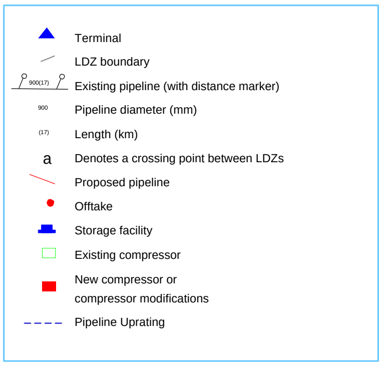


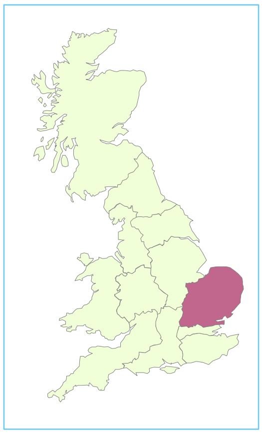




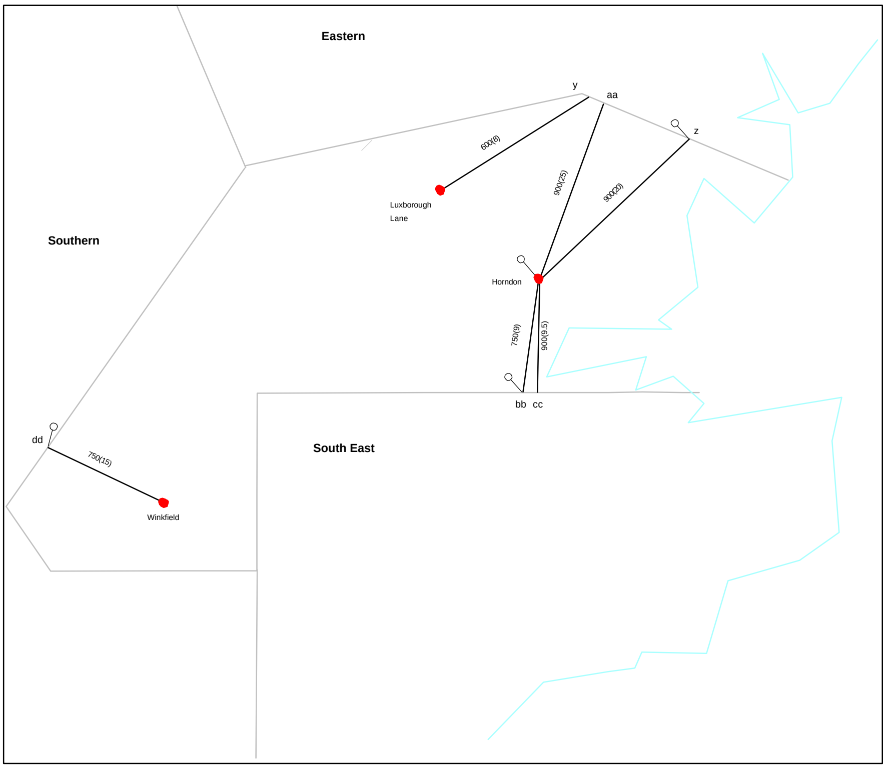
Eastern (EA) – NTS

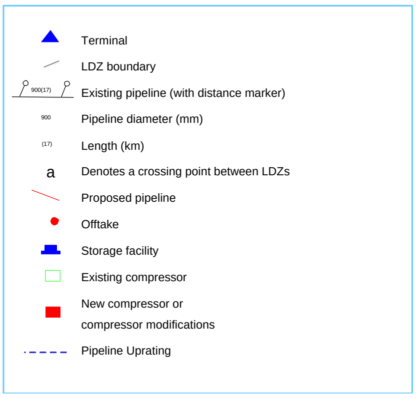


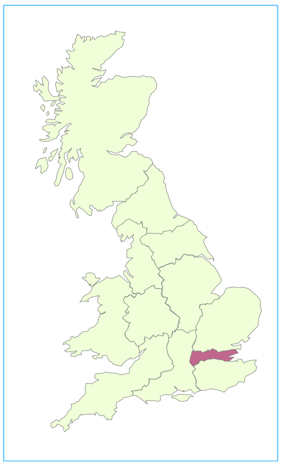




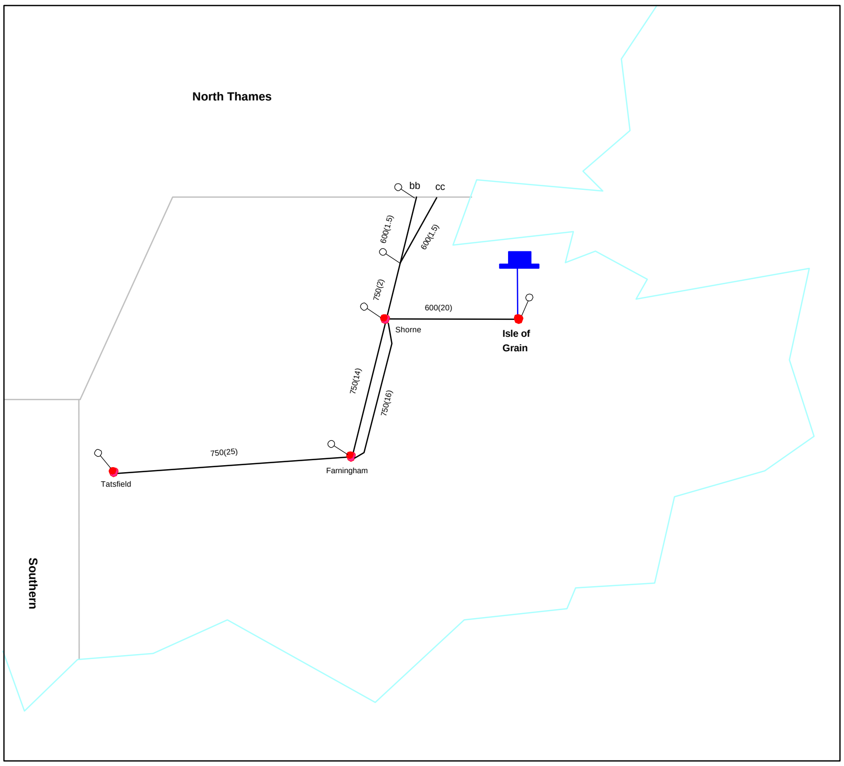
North Thames (NT) – NTS

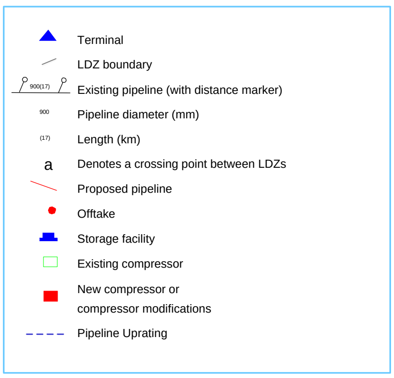


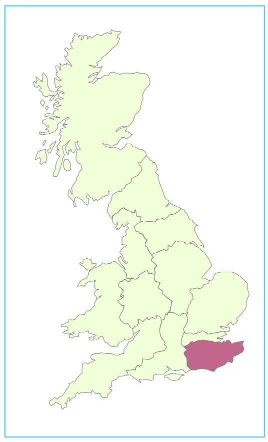




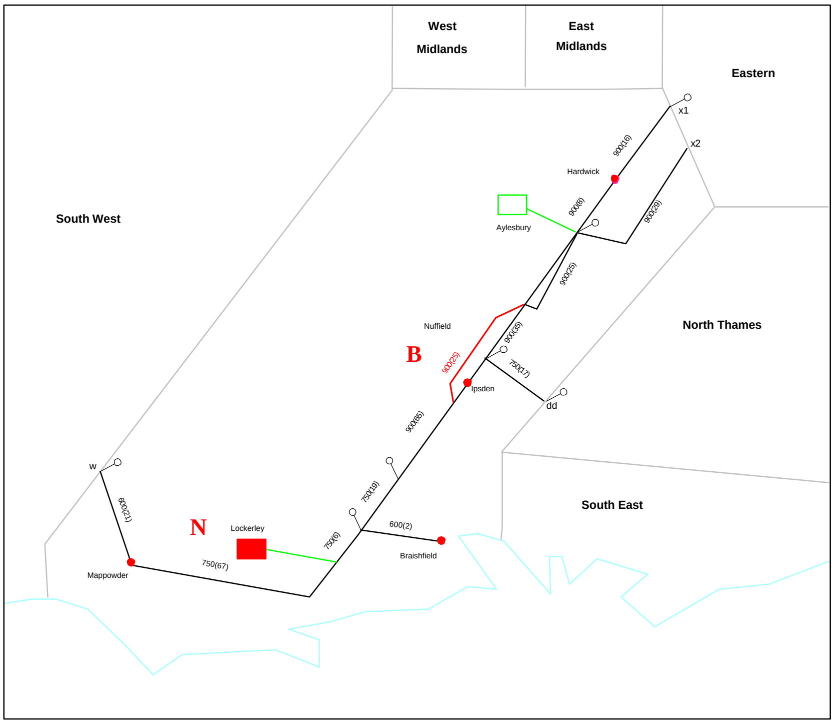
South East (SE) – NTS

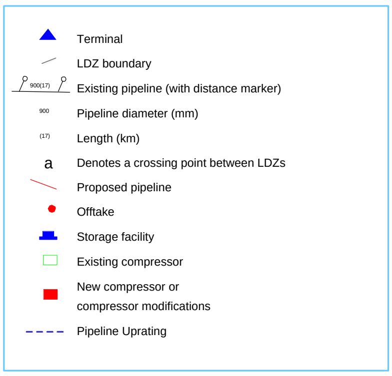


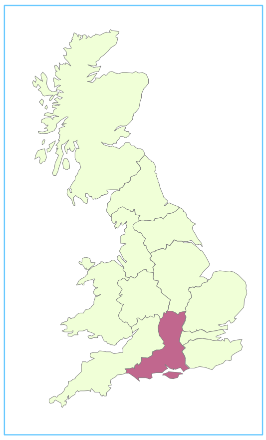




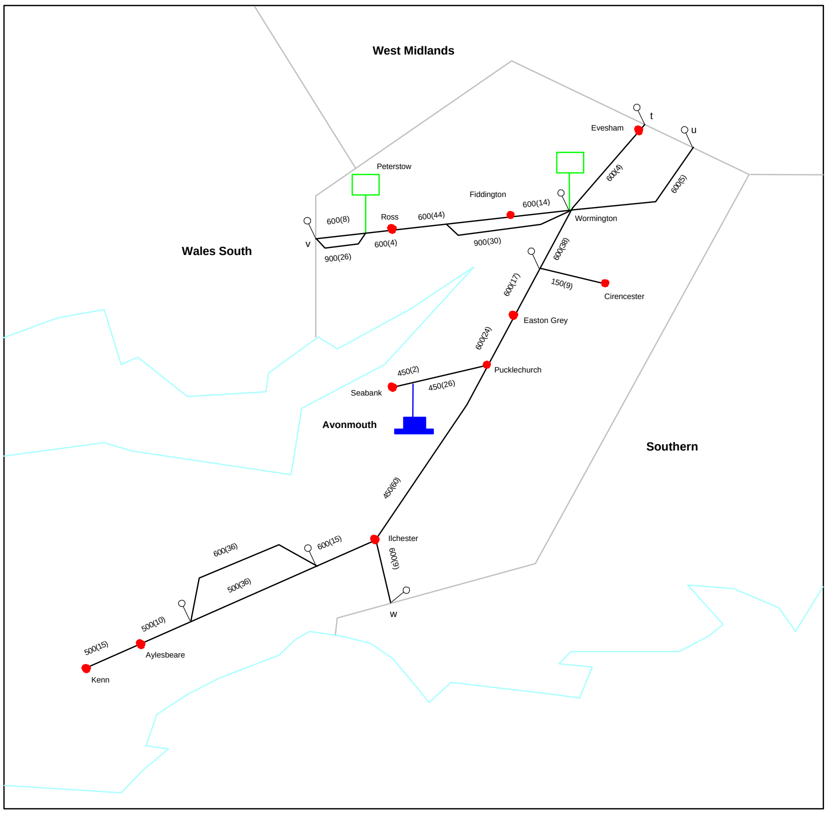
Southern (SO) – NTS

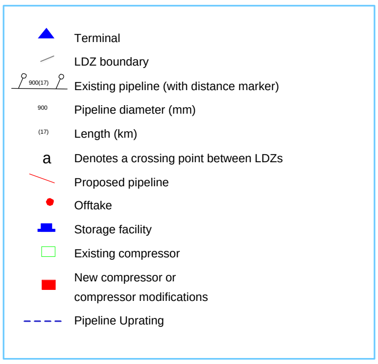


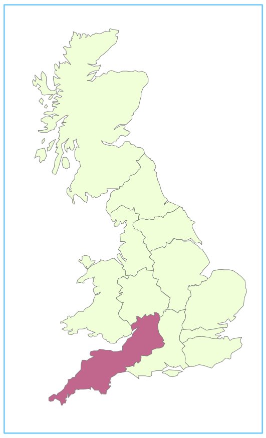




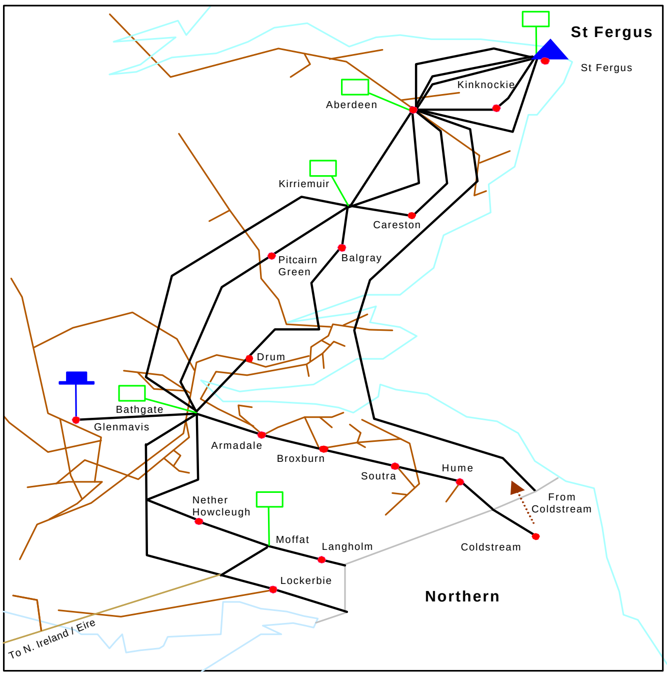
South West (SW) – NTS



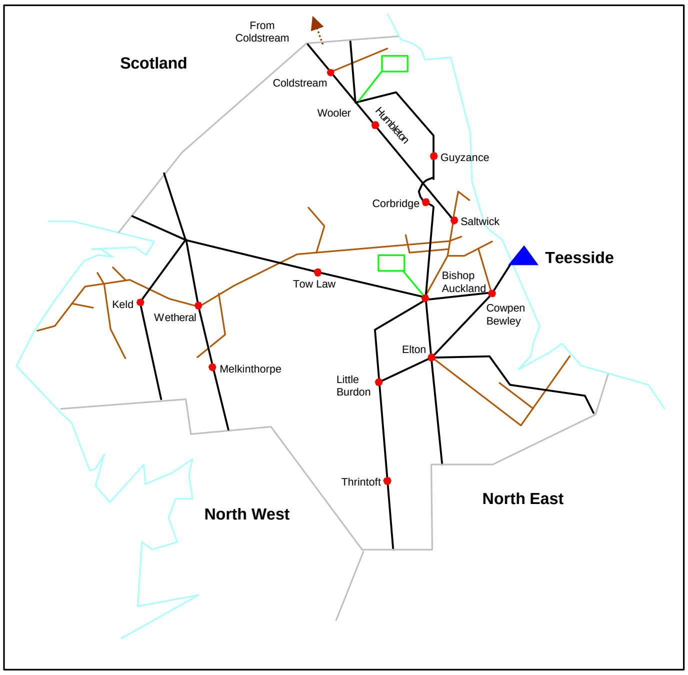




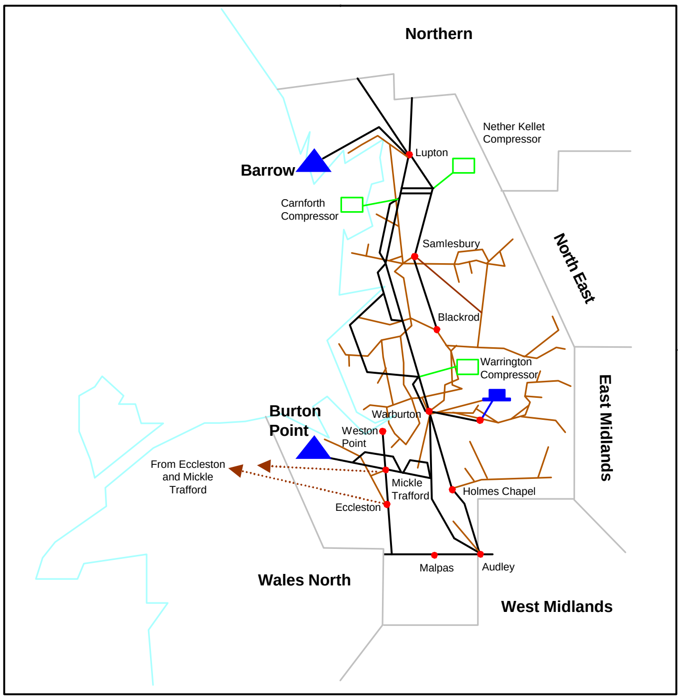
Scotland (SC) Network Code LDZ – LTS



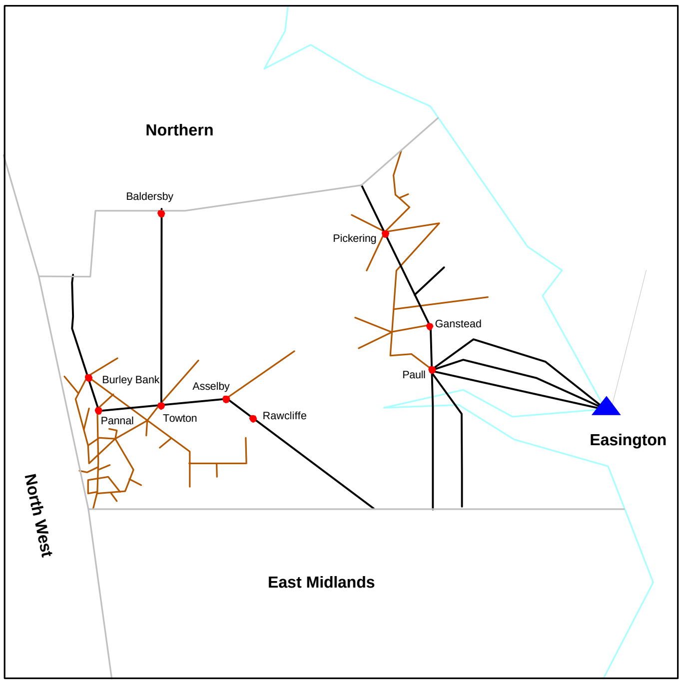
Northern (NO) Network Code LDZ – LTS



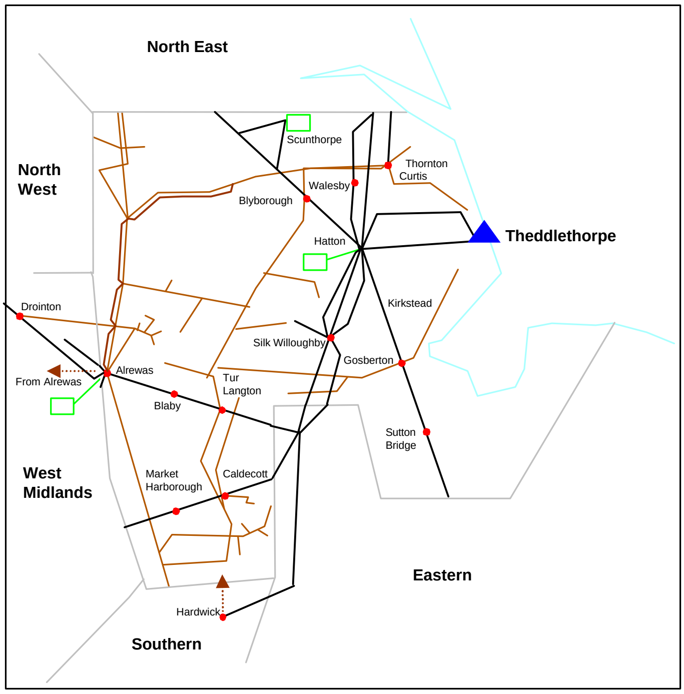
North West (NW) Network Code LDZ – LTS



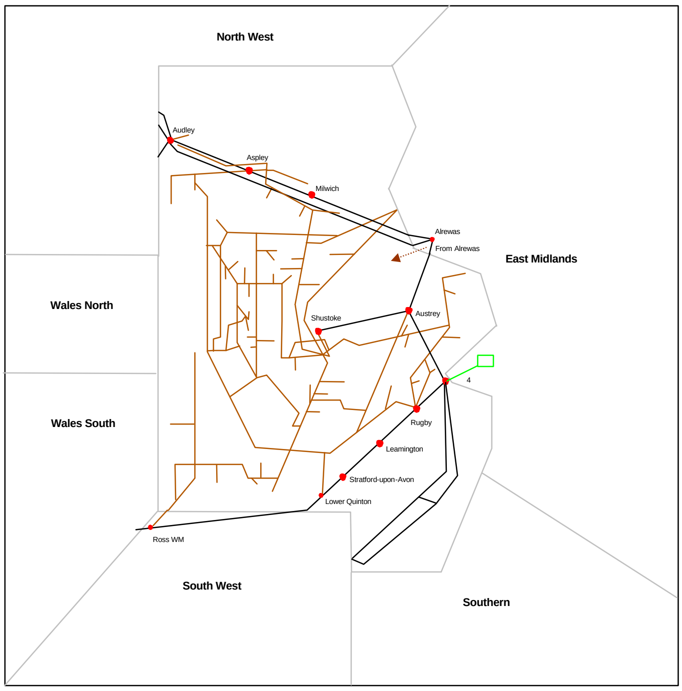
North East (NE) Network Code LDZ – LTS



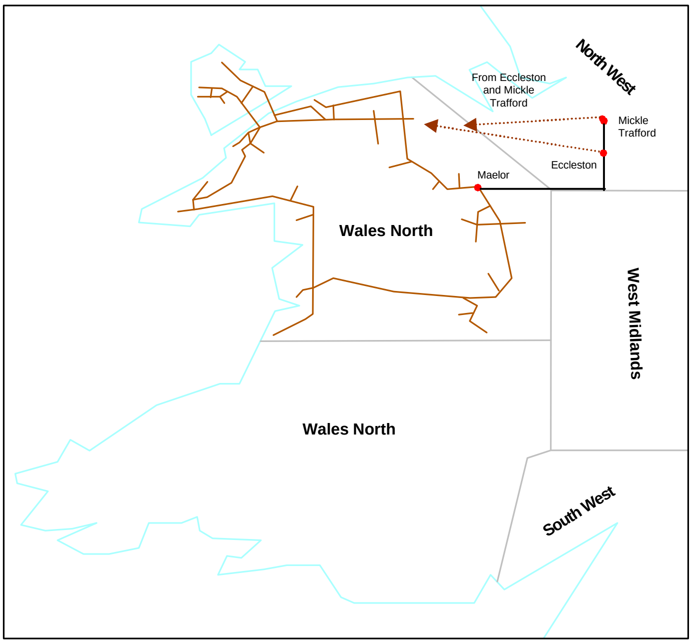
East Midlands (EM) Network Code LDZ – LTS



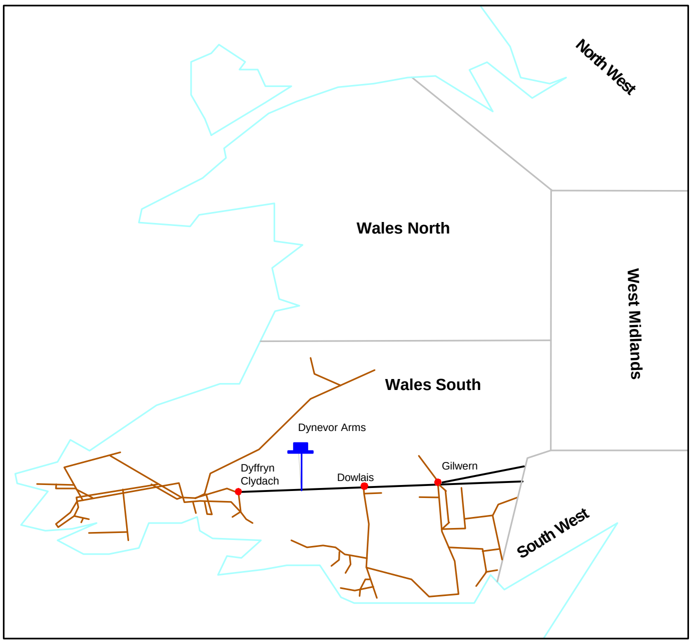
West Midlands (WM) Network Code LDZ – LTS



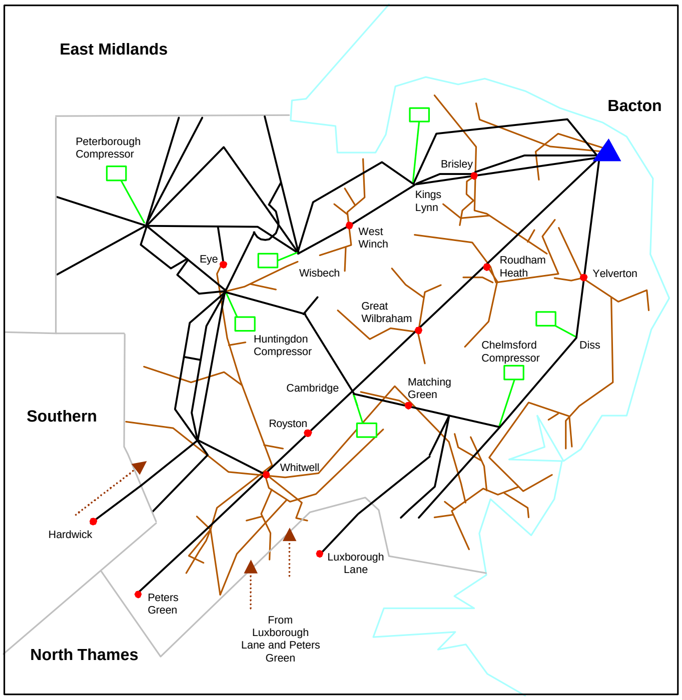
Wales North (WN) Network Code LDZ – LTS



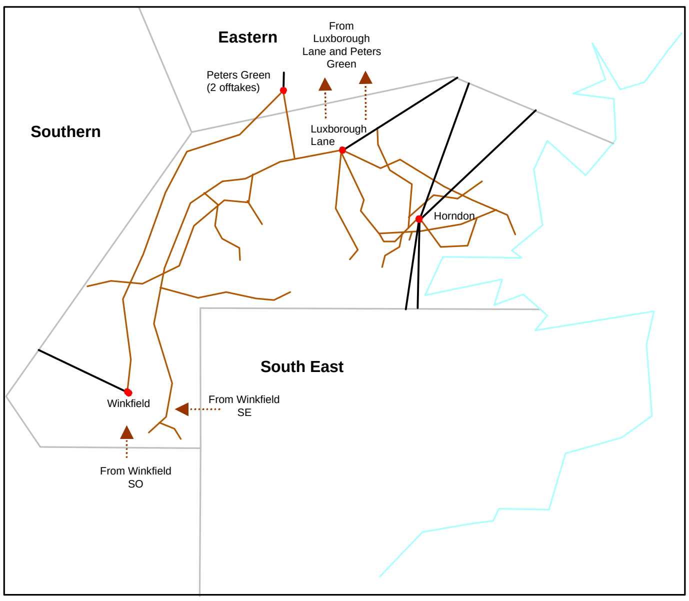
Wales South (WS) Network Code LDZ – LTS



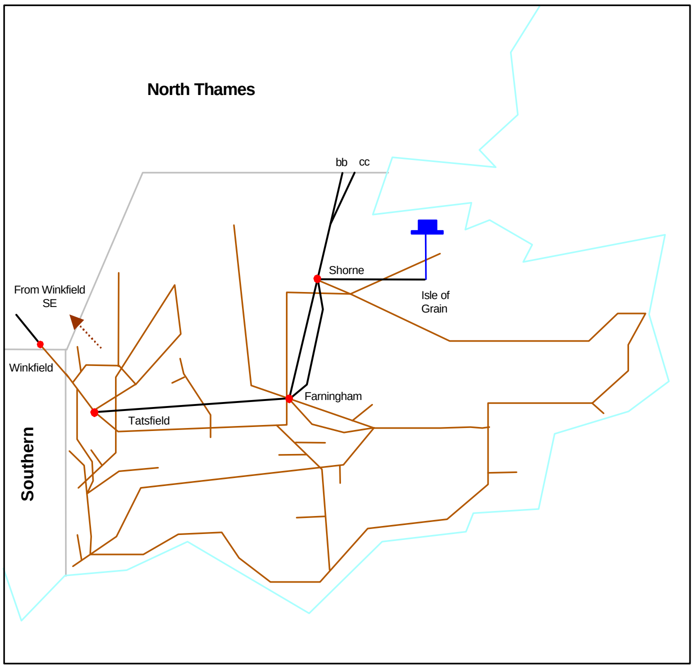
Eastern (EA) Network Code LDZ – LTS



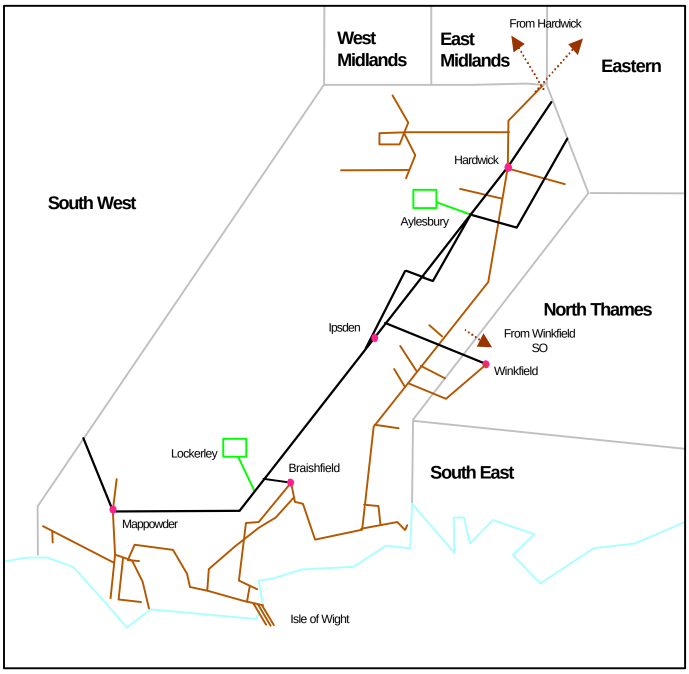
North Thames (NT) Network Code LDZ – LTS



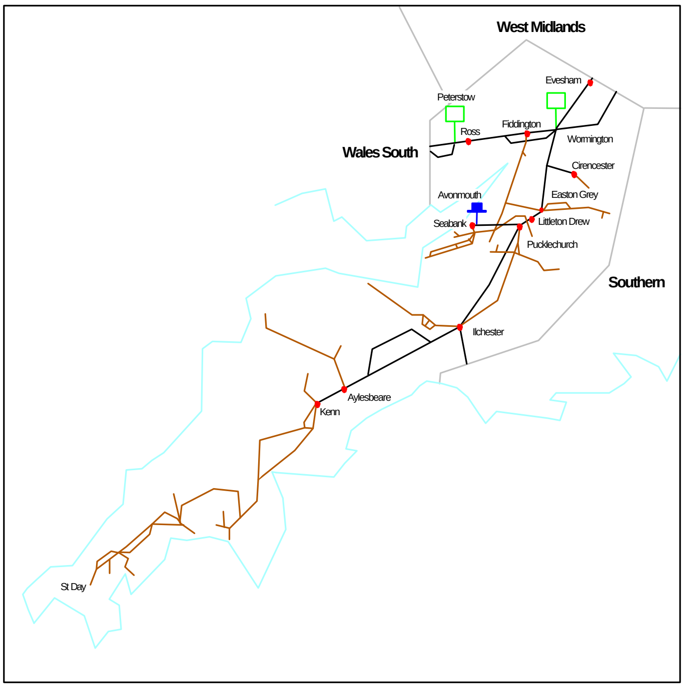
South East (SE) Network Code LDZ – LTS



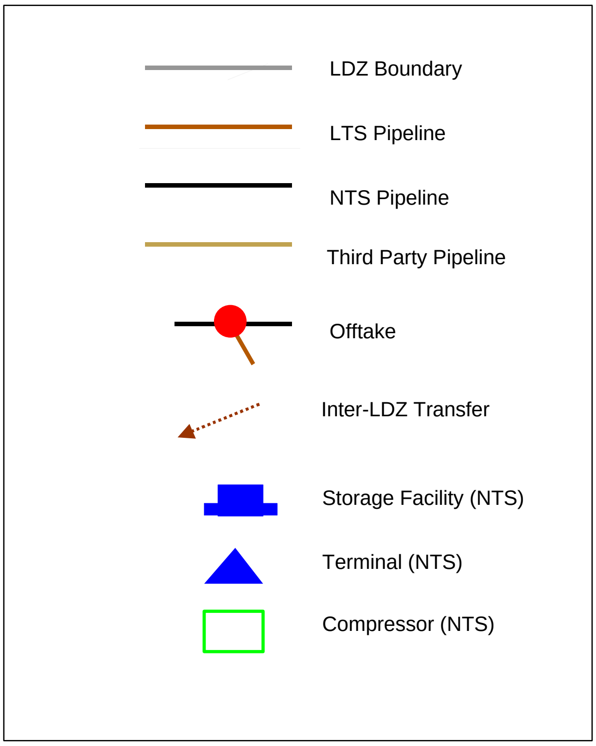
Southern (SO) Network Code LDZ – LTS



South West (SW) Network Code LDZ – LTS



Key - Network Code LDZ Map



Appendix Five

Connections to Transco's System

A5.1 Introduction

Within the space of a few years, the gas industry in Britain has evolved from a situation where we provided all new connections, to one where many alternative connection services are now available on a competitive basis.

Indeed, whilst we continue to offer connection services in line with our Gas Act obligations, customers and developers now have the option to choose other parties to build their facilities, have the connection vested in or adopted by the host gas transporter (depending upon circumstances), pass assets to a chosen system operator, transporter, or retain ownership of them.

The following are the generic classes of connection:

- Entry Connections: connections to delivery facilities processing gas from gas producing fields or, potentially in the future, LNG vapourisation (i.e. importation) facilities, for the purpose of delivering gas into our system.
- Exit Connections: connections that allow gas to be offtaken from our system or Connected System Exit Points (CSEPs). There are several types of connected system including:
    - A pipeline system operated by another gas transporter.
    - Any other non-Transco pipeline transporting gas to premises consuming more than 2,196MWh per annum.
- Storage Connections: connections to storage facilities for the purpose of temporarily offtaking gas from our system and delivering it back at a later date.
- International Interconnector Connections: connections to pipelines connecting Britain to other countries that may both offtake gas from and deliver gas to our system.

Please note that Storage and International Interconnector Connections may both deliver gas to the system and offtake gas from the system and therefore specific arrangements pertaining to both Entry and Exit Connections will apply.

In addition to new pipes being termed connections, any requirement to increase the quantity of gas delivered or offtaken is also treated as a new connection.

A5.2 General Information Regarding Connections

Our connection policy for all categories of connection is set out in the publication "Standard Condition 4B Of The Gas Transporter Licence – Transco Statement Of Principles And Methods To Be Used To Determine Charges Of Connection Services" (Licence Condition 4B Statement), which is supported by the Connections Services Charges Document.

Both documents can be downloaded from our web site (www.transco.uk.com), or can be obtained by writing to the following address:

Mr David Halsey
Network Policy
National Grid Transco
NGT House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

Additional information relating to the connection process, including contact details, can also be found on the website.

It should be noted that any person wishing to connect to our system, or requiring increased flow should contact us as early as possible to ensure that requirements can be met on time, particularly if system reinforcement is required as outlined in A5.4.3.

A5.3 Additional Information Specific to System Entry, Storage and Interconnector Connections

We require a Network Entry Agreement, Storage Connection Agreement or Interconnector Agreement, as appropriate, with the respective operator of all delivery, storage and interconnector facilities to establish, among other things, the gas quality specification, the physical location of the delivery point and the standards to be used for both gas quality and the measurement of flow.

A5.3.1 Network Entry Quality Specification

For any new entry connection to our system, the connecting party should notify us as soon as possible as to the likely gas composition. We will then determine whether the gas can be accepted taking into account our existing statutory and contractual obligations. Due to continuous changes being made to the system, any undertaking made by us on gas quality prior to signing a NEA will normally only be indicative.

Our ability to accept gas into the system is affected by, among other things, gas quality, the location of the system entry point, volumes entered and the quality and volume of gas already being transported on the system. In assessing the acceptability of any proposed gas composition, we will take account of:

a) Our ability to continue to meet our statutory obligations with respect to gas quality (including, but not limited to, the Gas Safety (Management) Regulations 1996);
b) The implications of the proposed gas composition on system running costs; and
c) Our ability to continue to meet our contractual obligations

For indicative purposes, the specification set out below is usually acceptable for most locations.

1. Hydrogen Sulphide
    - Not more than 5mg/m^3
2. Total Sulphur
    - Not more than 50mg/m^3

3. Hydrogen
   - Not more than 0.1% (molar)
4. Oxygen
   - Not more than 0.001% (molar)
5. Hydrocarbon Dewpoint
   - Not more than -2°C at any pressure up to 85barg
6. Water Dewpoint
   - Not more than -10°C at 85barg or the equivalent water content at other delivery pressures
7. Wobbe Number (real gross dry)
   - The Wobbe Number shall be in the range 47.20 to 51.41MJ/m^3
8. Incomplete Combustion Factor (ICF)
   - Not more than 0.48
9. Soot Index (SI)
   - Not more than 0.60
10. Gross Calorific Value (real gross dry)
    - The Gross Calorific Value (real gross dry) shall be in the range 36.9 to 42.3MJ/m^3, in compliance with the Wobbe Number, ICF and SI limits described above. Subject to gas entry location and volumes, we may set a target for the Calorific Value within this range.
11. Inerts
    - Not more than 7.0% (molar) subject to
        - Carbon Dioxide: not more than 2.0% (molar)
        - Nitrogen: not more than 5.0% (molar)
12. Contaminants
    - The gas shall not contain solid, liquid or gaseous material that may interfere with the integrity or operation of pipes or any gas appliance within the meaning of regulation 2(1) of the Gas Safety (Installation and Use) Regulations 1998 that a consumer could reasonably be expected to operate
13. Organo Halides
    - Not more than 1.5 mg/m3
14. Radioactivity
    - Not more than 5 Becquerels/g
15. Odour
    - Gas delivered shall have no odour that might contravene the statutory obligation not to transmit or distribute any gas at a pressure below 7 barg, which does not possess a distinctive and characteristic odour

16. Pressure
    - The delivery pressure shall be the pressure required to deliver natural gas at the Delivery Point into our Entry Facility at any time taking into account the back pressure of our System at the Delivery Point as the same shall vary from time to time
    - The entry pressure shall not exceed the Maximum Operating Pressure at the Delivery Point.
17. Delivery Temperature
    - Between 1°C and 38°C

Note that the Incomplete Combustion Factor (ICF) and Soot Index (SI) have the meanings assigned to them in the Gas Safety (Management) Regulations 1996 Schedule 3 (GS(M)R).

In addition, where a limit on a gas quality parameter is equal to that stated in GS(M)R, we may require an operational tolerance to be included within the NEA to ensure compliance with the GS(M)R.

A5.4 Additional Information Specific to System Exit Connections

Any person can contact us to request a connection, whether a shipper, operator, developer or end-user. However gas can only be offtaken where the Supply Point so created has been confirmed by a shipper, in accordance with the Network Code.

A5.4.1 Offtake Pressures

A5.4.1.1 National Transmission System (NTS) Connections

The Applicable Offtake Pressure for the NTS, as referred to in Network Code Section J 2.1 is normally 25barg. Although system pressure is typically higher, it will be subject to variation over time and location on the network. We currently plan normal NTS operations with start of day pressures no lower than 33barg, but such pressure cannot be guaranteed as pressure management is a fundamental aspect of operation of an economic and efficient system.

NTS offtake pressures at any location will vary due to:

- gas demand
- gas supply pressures at entry points
- compressor operation
- pipeline sizes and maximum operating pressures
- special operations such as maintenance and system development works

Offtake pressure also varies within day, from day to day, season to season and year to year. As a general rule, NTS offtake pressures tend to be higher at pressure sources such as entry points and outlets of operating compressors, and lower at the system extremities and inlets to operating compressors.

Our policy is to provide, on reasonable request, forecast information and illustrative historical records for specific NTS connection enquiries.

Notwithstanding the above, Shippers may request a "specified pressure" for any Supply Meter Point, connected to any pressure tier, in accordance with Network Code J 2.2.

A5.4.1.2 Distribution Network Connections

Gas will normally be made available for offtake to consumers at a pressure that is compatible with a regulated metering pressure of 21mbarg. Information on the design and operating pressures of distribution pipes can be obtained by contacting the appropriate Distribution Network office.

Higher operating pressures may be available, depending upon circumstances, however payment is required for reinforcement required as a result of the provision of requested elevated pressure and the pressure may not be guaranteed. Further detail relating to this matter may be found in our Licence Condition 4B Statement or by contacting the appropriate Distribution Network office.

A5.4.2 Self Lay Pipes or Systems

In accordance with S.10(6) of the Gas Act, and subject to the principles set out in the published Licence Condition 4B Statement and the terms and conditions of the contract between us and the customer in respect of the proposed connection, where a party wishes to lay their own service pipe to premises expected to consume 2,196MWh per annum or less, ownership of the pipe will vest in us once the connection to the our system has been made.

Where the connection is for a pipe laid to premises expected to consume more than 2,196MWh per annum or the connection is to a pipe in our system which is not a relevant main, self laid pipes do not automatically vest in us. However, subject to the principles set out in the published Licence Condition 4B Statement and the relevant contractual terms and conditions, we may take ownership of pipes to such premises.

Parties considering laying a pipe that will either vest in us or is intended to come into our ownership should refer to the publication Licence Condition 4B Statement and make contact with the appropriate Distribution Network office prior to the planning phase of any project.

A5.4.3 Reasonable Demands for Capacity

Operating under the Gas Act 1986 (as amended 1995), we have an obligation to develop and maintain an efficient and economical pipeline system and, subject to that, to comply with any reasonable request to connect premises, provided that it is economic to do so.

However, in many instances, specific system reinforcement may be required to maintain system pressures for the winter period after connecting a new supply or demand. Details of how we charge for reinforcement and the basis on which contributions may be required can be found in the Licence Condition 4B Statement. Please note that dependent on scale, reinforcement projects may have significant planning, resourcing and construction lead times and that as much notice as possible should be given. In particular, we will typically require two to four years notice of any project requiring the construction of high pressure pipelines or plant although in certain circumstances project lead times may exceed this period.

Appendix Six

Gas Transporter Licence Amendments

A6.1 Introduction

On 27 September 2002, Ofgem directed that modifications be made to our Gas Transporter (GT) Licence. The revised arrangements introduce a number of new incentives and modify existing incentives. Changes to the Network Code have been introduced to reflect the new arrangements.

Incentives are now placed on us for:

- Entry Capacity Investment
- Entry Capacity Buy-Back
- Exit Capacity
- System Balancing
- Residual Gas Balancing
- Internal Costs

A6.2 Entry Capacity Investment

The Entry Capacity Investment incentive has been established to encourage us to provide an efficient level of investment in response to customer demand. It is also designed to enable the supply of entry capacity to deviate either side of a central case in response to that level of customer demand.

We will periodically make available, via an auction, quantities of capacity, known as baseline capacity, as specified in our GT Licence. In January 2003 a cleared price auction was introduced to enable capacity to be bought in blocks of calendar quarters for a period from two years in advance of a gas year up to thirteen years ahead. Demand can be placed for quantities that in aggregate exceed the baseline quantity offered. That process is achieved by shippers placing bids for volumes against a range of prices published by us. If sufficient sustained demand above baseline is demonstrated then we can apply to the Authority for approval to allocate extra quantities of entry capacity. Our decision whether to seek approval will be based on the existence of sufficient demand and the satisfaction of the conditions of our Incremental Entry Capacity Release Methodology (for details of IECR methodology please refer to the document "Incremental Entry Capacity Release Statement" contained on the website www.transco.uk.com under Publications). If additional capacity is released then we will be allowed additional revenue in accordance with our Entry Capacity Investment incentive.

TABLE A6.2A – Initial NTS SO Baseline Entry Capacity (GWh/day)

Terminal	**2002/3**	**2003/4**	**2004/5**	**2005/6**	**2006/7**
Bacton	1374	1481	1655	1745	1745
Barrow	731	711	711	712	712
Easington	995	887	1027	1062	1062
St Fergus	1520	1549	1628	1648	1677
Teesside	819	741	751	761	761
Theddlethorpe	682	565	791	848	848
Glenmavis	99	99	99	99	99
Partington	215	215	215	215	215
Avonmouth	149	149	149	149	149
Isle of Grain	218	218	218	218	218
Dyenvor Arms	50	50	50	50	50
Hornsea	175	175	175	175	175
Hatfield Moor (storage)	54	54	54	54	54
Hatfiled Moor (onshore)	1	1	1	1	1
Aldborough	0	233	233	233	233
Cheshire	0	0	107	161	214
Hole House Farm	26	26	26	26	26
Wytch Farm	3.2	3.2	3.2	3.2	3.2
Burton Point	55	55	55	55	55

A6.3 Entry Capacity Buy-Back

The buy back incentive provides an inducement to the System Operator to efficiently manage the trade offs between increasing incremental capacity release and the costs of capacity management that arise when gas flows against firm capacity rights exceed system capability.

Broadly, a neutrality arrangement is operated which nets off, at the end of each day, the costs and revenues accrued to each shipper. The incentive arrangement is based on a central case annual aggregate neutrality cost of £35m. If, primarily by prudent use of capacity management tools we are able to hold neutrality costs below the central case then the savings are shared between us and the shippers (shippers receive 50%). Similarly if aggregate neutrality costs exceed the central case then both we and the shippers are required to contribute (shippers contribute 65%) to the additional expense.

A6.4 Exit Capacity

The exit capacity incentive has three components, Interruption, Growth and Constrained Storage. Additional credits to a shipper are now payable if a site in its portfolio is interrupted on more than fifteen occasions in any formula year. The credit for each day of interruption is equal to 1/15th of the annual firm exit capacity charge that the particular site would have paid had it been a firm load. We are incentivised to minimise the costs relating to interruption.

We are also incentivised to minimise the costs of providing additional system exit capacity beyond the baseline quantity identified in our GT Licence. The calculation is based upon the level of booked exit capacity in each winter period.

The above two components are incentivised in combination so as to encourage efficient trade-off of costs and benefits between the components. Shippers receive 50% of any incentive out-performance but contribute 75% to any under-performance. Our upside and downside potential is limited by a cap and collar respectively.

A further element of the exit incentive is intended to encourage us to minimise the cost of Constrained LNG services to meet forecast transportation needs. Only a fixed pre-determined cost allowance for this service is passed on to shippers through the transportation charges.

TABLE A6.4A – NTS Baseline Firm Exit Capacity (GWh/day)

	2002/3	2003/4	2004/5	2005/6	2006/7
Firm exit capacity by LDZs					
Scotland	343	348	355	362	367
Northern	265	271	278	283	287
North West	538	550	557	563	568
North East	279	283	287	290	293
East Midlands	464	470	477	483	488
West Midlands	454	459	464	470	475
Wales North	51	52	54	55	57
Wales South	198	201	204	208	211
Eastern	359	366	372	377	382
North Thames	508	512	516	520	525
South East	516	523	526	529	532
Southern	380	394	402	409	414
South West	279	284	290	295	299
Total firm exit capacity for LDZ loads	4633	4713	4782	4844	4897
Firm exit capacity for NTS loads	1488	1529	1592	1653	1691
Total firm baseline NTS exit capacity	6121	6241	6374	6497	6588

TABLE A6.4B – NTS Baseline Interruptible Exit Capacity (GWh/day)

	2002/3	2003/4	2004/5	2005/6	2006/7
Firm exit capacity by LDZs					
Scotland	47	54	56	58	60
Northern	33	34	37	38	39
North West	72	75	77	78	78
North East	38	40	41	42	43
East Midlands	75	77	89	93	99
West Midlands	35	36	37	37	37
Wales North	7	7	8	8	9
Wales South	28	29	31	32	32
Eastern	36	36	37	37	37
North Thames	40	45	47	48	49
South East	40	44	44	51	61
Southern	36	37	38	38	40
South West	32	33	34	34	34
Total firm exit capacity for LDZ loads	521	548	576	595	619
Firm exit capacity for NTS loads	1073	1141	1142	1147	1148
Total firm baseline NTS exit capacity	1594	1689	1718	1742	1767

A6.5 System Balancing

System Balancing comprises two incentives (i) gas costs and (ii) system reserve.

i. The gas cost incentive principally relates to the costs of providing gas and electricity to meet our NTS Shrinkage requirements. The incentive is of a sliding scale nature and we obtain incentive revenue for superior performance where the actual costs of NTS Shrinkage are lower than a target level predetermined by Ofgem. The level of incentive reward is proportional to the degree of underspend (shippers receive 75%). Conversely where actual costs for NTS Shrinkage are beyond the target set by Ofgem then our performance is inferior and we face a proportion of the degree of overspend (shippers contribute 80%). Our upside and downside potential is limited by a cap and collar respectively. This form of incentive allows us and shippers to jointly benefit from any underspend or to jointly face the costs of any overspend.

   The target for the gas cost incentive is set with respect to a volume of gas for each year of the price control, a gas pricing formula for the gas volumes for each year and a fixed annual amount for procuring fuel for electric compression.

   In effect we are incentivised to reduce the volume of NTS Shrinkage and to purchase the necessary quantities of electricity and gas at a better price than that used to set the cost target.

ii. The system reserve incentive is similar to the gas cost incentive in that it is of a sliding scale nature with a performance measure based on the cost of procuring storage capacity for the purposes of satisfying our operating margins requirements. However, we are exposed to the full cost of any overspend and retain the full benefit of any underspend; no cap or collar applies. We are incentivised to only purchase necessary volumes of storage capacity sufficient to meet our obligations at efficient prices.

A6.6 Residual Gas Balancing

Our Residual Gas Balancing Incentive provides an incentive on each day to trade gas at efficient prices and to minimise the swing of linepack volumes within the NTS. The incentive was formerly described in the Network Code and is now described in our GT Licence. Briefly, for the price incentive component, our reward or payment is a function of the difference between the prices of our marginal buys and marginal sell trades, relative to the system average price for that day. In principle we are incentivised to keep the difference between our marginal buy and sell prices as close as possible. For the linepack component small differences between our opening and closing linepack positions, relative to a predetermined value, result in access to incentive upside whilst differences beyond the predetermined value result in incentive downside. The sum of the daily price incentive payments and the daily linepack incentive payments are subject to an annual cap and collar.

A6.7 Internal Costs

We are encouraged to trade off operating costs across the range of the System Operator’s management functions in order to maximise efficiency. One such example might be that obtaining certain staff skills through recruitment increases the manpower costs of the SO but might lead to lower costs being incurred through the other incentives. Where the benefits of such strategies outweigh the costs the shippers share in those benefits. The form of this incentive is of sliding scale in nature without a cap or collar on the level of shared benefit or cost that can be achieved (shippers receive 60% of any out performance, but bear 65% of any overspend).

Appendix Seven

Glossary

Advanced Reservation of Capacity Agreement (ARCA)

An agreement between us and Shippers relating to future NTS pipeline capacity for large sites in order that Shippers can book NTS Exit Capacity in accordance with Network Code provision to meet gas requirements of large projects at a later date.

Annual Quantity (AQ)

The AQ of a supply point is its annual consumption over a 365 day year, under conditions of average weather.

Bar

The unit of pressure that is approximately equal to atmospheric pressure (0.987 standard atmospheres). Where bar is suffixed with the letter g, such as in barg or mbarg, the pressure being referred to is gauge pressure, i.e. relative to atmospheric pressure.

One millibar (mbarg) equals 0.001 bar.

Base Plan Assumptions (BPA)

A document that until recently was produced by us on an annual basis that describes our supply and demand forecasts for the next ten years. This information is now contained in our Ten Year Statement.

Calorific Value (CV)

The ratio of energy to volume measured in Megajoules per cubic meter (MJ/m^3) which for a gas is measured and expressed under standard conditions of temperature and pressure.

Composite Weather Variable (CWV)

A single measure of weather for each LDZ, incorporating the effects of both temperature and wind speed. A separate composite weather variable is defined for each LDZ.

Combined Cycle Gas Turbine (CCGT)

A Combined Cycle Gas Turbine is a unit whereby electricity is generated by a gas powered turbine and also a second turbine. The hot exhaust gases expelled from the first turbine are fed into the heat exchanger to generate steam which powers the second turbine.

Combined Heat and Power (CHP)

The simultaneous generation of electricity and heat for use within buildings or processes, by recovery of the heat produced in the power generation process. As such, CHP represents the highest efficiency means of generating electricity.

Compressor Station

An installation that uses gas turbine or electricity driven compressors to boost pressures in the pipeline system. Used to increase transmission capacity and move gas through the network.

Connected System Exit Point (CSEP)

A connection to a more complex facility than a single supply point. For example a connection to a pipeline system operated by another Gas Transporter.

Cubic Metre (m^3)

The unit of volume, expressed under standard conditions of temperature and pressure, approximately equal to 35.37 cubic feet. One million cubic metres (mcm) is equal to 10^6 cubic metres, one billion cubic metres (bcm) equals 10^9 cubic metres.

Daily Flow Notification (DFN)

A communication between a Delivery Facility Operator (DFO) and us, indicating hourly and end of day entry flows from that facility.

Daily Metered Supply Point

A supply point fitted with equipment, for example a datalogger, that enables meter readings to be taken on a daily basis. Further classified as SDMC, DMA, DMC or VLDMC according to annual consumption.

Datalogger

An electronic device that automatically records, stores and transmits meter readings (such transmission usually being via PSTN lines).

Delivery Facility Operator (DFO)

Operators of the reception terminals, which process and meter gas deliveries from offshore pipelines before transferring the gas to our system.

Distribution Network (DN)

An administrative unit responsible for the operation and maintenance of the local transmission system (LTS) and <7barg distribution networks within a defined geographical boundary. There are currently eight DNs, each consisting of one or more LDZs, supported by a national Emergency Services organisation.

Distribution System

A network of mains operating at three pressure tiers: intermediate (2 to 7barg), medium (75mbar to 2barg) and low (less than 75mbarg).

Diurnal Storage

Gas stored for the purpose of meeting, among other things, within day variations in demand. Gas can be stored in special installations, such as gasholders, or in the form of linepack within transmission, i.e. >7barg, pipeline systems.

Exit Zone

A geographical area (within an LDZ) that consists of a group of supply points that, on a peak day, receive gas from the same NTS offtake.

FALCON

A computer program which simulates the operation of the transmission system. It is used to optimise future system expansion plans as forecast supply and demand change over time.

Formula Year

A twelve month period commencing 1st April, predominantly used for regulatory and financial purposes.

Gas Transporter (GT)

Formerly Public Gas Transporter (PGT). GT's, such as us, are licensed by the Gas and Electricity Markets Authority to transport gas to consumers.

Gasholder

A vessel used to store gas for the purposes of providing diurnal storage.

Gas Supply Year

A twelve month period commencing 1st October, also referred to as a Gas Year.

Interconnector

A pipeline transporting gas to another country. The Irish interconnector transports gas across the Irish Sea to both the Republic of Ireland and Northern Ireland. The Continental Interconnector transports gas between Bacton and Zeebrugge. The Continental Interconnector is capable of flowing gas in either direction.

Interruptible Service

A service that offers lower transportation charges but where we can interrupt the flow of gas to the supply point.

Kilowatt hour (kWh)

A unit of energy used by the gas industry. Approximately equal to 0.0341 therms. One Megawatt hour (MWh) equals 10^3 kWh, one Gigawatt hour (GWh) equals 10^6 kWh, and one Terawatt hour (TWh) equals 10^9 kWh.

Linepack

The volume of gas within the National or Local Transmission System at any time.

Liquefied Natural Gas (LNG)

Gas stored in liquid form. Can be firm or constrained (CLNG). Shippers who book a constrained service agree to allow us to use some of their gas to balance the system.

Load Duration Curve (1 in 50 Severe)

The 1 in 50, or severe, load duration curve is that curve which, in a long series of years, with connected load held at the levels appropriate to the year in question, would be such that the volume of demand above any given demand threshold (represented by the area under the curve and above the threshold) would be exceeded in one out of fifty years.

Load Duration Curve (Average)

The average load duration curve is that curve which, in a long series of winters, with connected load held at the levels appropriate to the year in question, the average volume of demand above any given threshold, is represented by the area under the curve and above the threshold.

Local Distribution Zone (LDZ)

A geographic area supplied by one or more NTS offtakes. Consists of LTS and distribution system pipelines.

Local Transmission System (LTS)

A pipeline system operating at >7barg that transports gas from NTS offtakes to distribution systems. Some large users may take their gas direct from the LTS.

National Balancing Point (NBP)

A notional point which represents the NTS for balancing purposes.

National Transmission System (NTS)

A high pressure system consisting of terminals, compressor stations, pipeline systems and offtakes. Designed to operate at pressures up to 85 bar. NTS pipelines transport gas from terminals to NTS offtakes.

National Transmission System Offtake

An installation defining the boundary between the NTS and the LTS or a very large consumer. The offtake installation includes equipment for metering, pressure regulation, etc.

Network Code

The document that defines the contractual relationship between us and System Users.

Non-Daily Metered (NDM)

A meter that is read monthly or at longer intervals. For the purposes of daily balancing, the consumption is apportioned, using an agreed formula, and for supply points consuming more than 73.2MWh pa, reconciled individually when the meter is read.

Odorisation

The process by which the distinctive odour is added to gas supplies to make it easier to detect leaks. We provide odorisation at NTS offtakes.

Office of Gas and Electricity Markets (Ofgem)

The regulatory agency responsible for regulating the UK's gas and electricity markets.

On the day Commodity Market (OCM)

This market enables anonymous financially cleared on the day trading between market participants.

Operating Margins

Gas used by us to maintain system pressures under circumstances including periods immediately after a supply loss or demand forecast change before other measures become effective and in the event of plant failure, such as pipe breaks and compressor trips.

Own Use Gas (OUG)

Gas used by us to operate the transportation system. Includes gas used for compressor fuel, heating and venting.

Price Control Review (PCR)

Ofgem's periodic review of our allowed returns, the next PCR will set returns for the period April 2007 to March 2012.

Peak Day Demand (1 in 20 Peak Demand)

The 1 in 20 peak day demand is the level of demand that, in a long series of winters, with connected load held at the levels appropriate to the winter in question, would be exceeded in one out of 20 winters, with each winter counted only once.

Seasonal Normal Composite Weather Variable (SNCWV)

The seasonal normal value of the CWV for a LDZ on a day is the smoothed average of the values of the applicable CWV for that day in a significant number of previous years.

Shearwater Elgin Area Line (SEAL)

The offshore pipeline from the Central North Sea (CNS) to Bacton.

Shipper or Network Code Registered User (System User)

A company with a Shipper Licence that is able to buy gas from a producer, sell it to a supplier and employ a GT to transport gas to consumers.

Shrinkage

Gas that is input to the system but is not delivered to consumers or injected into storage. It is either Own Use Gas or Unaccounted for Gas.

Supplier

A company with a Supplier's Licence contracts with a shipper to buy gas which is then sold to consumers. A supplier may also be licensed as a shipper.

Supply Hourly Quantity (SHQ)

The maximum hourly consumption at a supply point.

Supply Offtake Quantity (SOQ)

The maximum daily consumption at a supply point.

Supply Point

A group of one or more meters at a site.

Therm

An imperial unit of energy. Largely replaced by the metric equivalent: the kilowatt hour (kWh). 1 therm equals 29.3071 kWh.

Transporting Britain's Energy

Our annual industry wide consultation process encompassing the Ten Year Statement, targeted questionnaires, individual company and industry meetings, feedback on responses and investment scenarios.

Unaccounted for Gas (UAG)

Gas lost during transportation. Includes leakage, theft and losses due to the method of calculating the Calorific Value.

UKCS

United Kingdom Continental Shelf.

UK-Link

A suite of computer systems that supports Network Code operations. Includes AT-Link for energy balancing; Supply Point Administration; Invoicing; and the Sites and Meters database.

Ullage

Ullage is the difference between pipeline capacity and actual / forecast pipeline flow.

Unbundled Service

An optional service, offered and priced separately from our core transportation services.

Appendix Eight

Conversion Matrix

To convert from the units on the left hand side to the units across the top multiply by the values in the table.

	To: Multiply	GWh	mcm	Million therms	Thousand toe
From:	GWh	1	0.092	0.034	0.086
	mcm	10.833	1	0.370	0.932
	Million Therms	29.307	2.710	1	2.520
	Thousand toe	11.630	1.073	0.397	1

Note: all volume to energy conversions assume a CV of 39 MJ/m^3

GWh = Gigawatt Hours

mcm = Million Cubic Metres

Thousand toe = Thousand Tonne of Oil Equivalent