National Grid Transco – Potential sale of gas distribution network businesses

Final Impact Assessment - Appendices

November 2004 255/04b

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This document is published in conjunction with the Final IA and the information, views, and opinions set out in this document should be read subject to any provisos included in the Final IA.

Appendix 1 Previous studies of the benefits case

1.1 A number of studies, commissioned by the industry, have sought to quantify the likely benefits of a potential DN sale. These include:

- a report commissioned by Ofgem and prepared by ILEX Energy Consulting Ltd[1];
- an RIA prepared by NGT[2]; and
- work undertaken by OXERA on behalf of British Gas Trading Ltd (BGT)[3].

1.2 Table A.1 below, sets out the three studies' evaluation of the (gross) benefits that the sale of four DNs may be likely to deliver to customers.

Table A.1: Comparison of potential benefit estimates (sale of four DNs) [4]

Study		Estimated benefits (2000 prices)
OXERA[5]	Low Case	£102m
	High Case	£134m
NGT[6]	No merger benefits	£356m
	Merger benefits	£558m
ILEX	No merger benefits	£319m

[1] This analysis forms an appendix to Ofgem's December document on DN sales. See *'National Grid Transco – Potential sale of network distribution businesses'*, Ofgem, December 2003, Appendix 2.
[2] *National Grid Transco - Potential Sale of Network Distribution Businesses Regulatory Impact Assessment*
[3] *Potential sales of National Grid Transco's distribution networks: Critical review of the preliminary regulatory impact Assessment* September 2003.
[4] It is noted that these estimates are provided in 2000 prices. However, the benefits estimates provided later in this chapter are stated in 2004 prices. As such, the numbers quoted for the OXERA / NGT / ILEX studies should be inflated before being compared to those derived within this document.
[5] In its analysis, OXERA made no estimate of additional merger benefits, furthermore, the benefits stated in this table do not include OXERA's estimate of the impact of losses of economies of scale.
[6] NGT benefits presented are assumed to be net of industry costs of £10m - £18m.

1.3 It should be noted that each of these studies assumed that four DNs would be sold to separate entities and hence four separately owned DN comparators, in addition to the Transco RDNs, would be created.

1.4 The following section provides a summary of the high-level results obtained by these studies (a more detailed description of their assumptions and methodologies are set out in Appendix 8).

OXERA report

1.5 BGT commissioned OXERA to undertake a critical review of the initial Ofgem RIA and to develop an independent analysis. The OXERA report put forward an alternative methodology for estimating the potential level of customer benefits, if between one and eight DNs were to be sold, which resulted in a range of potential gross benefits (i.e. not including estimated potential costs) of between £7 million and £218 million (in 2000 prices). As shown in Table A.1, in the event that four DNs were sold, OXERA estimated that potential benefits to customers may range from £102m to £134m (in 2000 prices) if no loss of scale economies are assumed.

1.6 OXERA's analysis suggested that the following factors were likely to be important in determining whether customers would benefit from a sale of one or more DNs:

- loss of scale economies;
- the number of DNs sold; and
- the efficiency of the DNs sold relative to other DNs.

1.7 OXERA's results suggested that customer detriment is most likely to occur if there are significant losses in scale economies and / or a smaller number of DNs are sold.

NGT Regulatory Impact Assessment

1.8 In December 2003, NGT submitted a document setting out NGT's detailed assessment of the achievable net consumer benefit (i.e. benefits net of costs) in the event of the sale of one or more of the DNs.

1.9 NGT suggested that Ofgem's preliminary RIA could arguably be considered to be conservative, in particular because it did not take into account potential multi-utility synergies available to buyers who already own overlapping distribution networks in the electricity and water sectors. NGT's base case assessment therefore included a potential "merger efficiency" benefit to customers that arose not out of comparative regulation *per se*, but because of more aggressive management techniques in the new companies and merger synergies.

1.10 NGT suggested that the range of benefits is likely to exceed that calculated by Ofgem and, at the top end, could be argued to exceed £500 million in 2000 prices.

ILEX report

1.11 Against this background, Ofgem commissioned ILEX to prepare an independent assessment of the potential costs associated with the sale of one or more DNs, including potential losses of economies of scale, as raised by OXERA. ILEX was also asked to review Ofgem's analysis of the estimated potential customer benefits from the sale of one or more DNs. Ofgem intended the report to be an independent contribution to the debate and does not endorse (or refute) ILEX's findings.

1.12 ILEX estimated the potential benefits and performed a number of sensitivity evaluations relating to the number of DNs sold, the extent to which merger savings are achievable, and the efficiency gains of RDNs and IDNs in the event of DN sales. ILEX also constructed a number of cost scenarios based on their expertise and discussions with some industry participants. ILEX concluded that, in most scenarios, NGT's proposals to sell one or more of its DNs are likely to be beneficial to customers. As shown in Table A.1, the base case estimate of benefits provided by ILEX in the event that four DNs are sold was £319m in 2000 prices.

1.13 This base case estimate did not incorporate an assumption regarding higher up-front savings as a result of merger benefits in addition to the on-going efficiency savings assumed. However, ILEX did assume that any losses in economies of scale that may arise as a result of DN sales, would be offset by merger benefits associated with economies of scope[7] in managing a DN jointly with an electricity Distribution Network Operator (DNO), or through financial engineering.

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[7] Economies of scope are savings that arise where it is cheaper to produce two products together than it is to produce each separately.

Appendix 2 Position papers and open letters

2.1 Table A.2 lists the Ofgem preliminary position papers and open letters that have been issued as part of the DN sales process. These papers can be found on the Gas Distribution Network Sale page of Ofgem's website.[8]

Table A.2: Position papers and open letters issued by Ofgem as part of DN sales

Title of paper	**Date issued**
Ofgem note on initial draft of private CLM licence condition	19 October 2004
Open letter: Updated timetable for Potential Gas Distribution Network Sales Project	15 October 2004
Open letter: Gas Distribution Price Controls - Further Clarification	6 October 2004
Ofgem position paper on Asset Risk Management survey[9]	24 August 2004
Ofgem preliminary position on Duration of Incentives[10]	24 August 2004
Ofgem preliminary position on the Business Separation requirements to apply between Distribution Networks	20 August 2004
Open Letter: Special Condition 18[11]	6 August 2004
Open letter: License Amendment Process	5 August 2004
Ofgem position paper on governance of charging methodologies[12]	3 August 2004
Ofgem preliminary position on the Uniform Network Code Modification Process & the constitution of the Governance Entity[13]	3 August 2004
Ofgem Position Paper on Pensions[14]	2 August 2004
Open Letter: Environmental Liabilities	23 July 2004
Ofgem position on governance of the Agency (presentation to DISG 14)	23 July 2004
Ofgem position on SOMSAs (presentation to DISG 14)	23 July 2004
Open letter: Timetable for Potential Gas Distribution Network Sales Project	16 July 2004
Ofgem position on merger policy[15]	6 July 2004
Open letter: RIA on Options for Exit Reform Industry letter	20 April 2004
Open letter: Gas Distribution Price Controls	16 March 2004

[8] http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/gasdistributionnetworksale
[9] This paper is located on Ofgem's website under papers for DISG 17.
[10] This paper is located on Ofgem's website under papers for DISG 17.
[11] This open letter was corrected by a letter published on 26 August 2004.
[12] This paper is located on Ofgem's website under papers for DISG 15.
[13] This paper is located on Ofgem's website under papers for DISG 15.
[14] This position paper was supplemented by a further paper published on 9 August 2004.
[15] This paper is located on Ofgem's website under papers for DISG 13.

2.2 In issuing these open letters and papers, Ofgem made it clear that there could be no expectation on the part of Transco, potential DN purchasers or any other interested parties either as to what the Authority's final decision in relation to the proposed DN sales may be, or as to the regulatory framework which may be implemented if the Authority consents to the proposal. These open letters and papers were provided on an informal basis and should not be treated as binding on the Authority. Nothing in these documents is to be construed as granting any rights or imposing any obligations on the Authority. The Authority's discretion in this matter will not be fettered by any statement made in these documents.

Appendix 3 Documents issued as part of DN sales consultation process

3.1 This appendix lists all documents issued as a part of the DN sales consultation process. It includes all documents and workgroup papers, excepting responses to consultation documents which are listed separately in Appendix 4.

3.2 All of these documents can be found on the Gas Distribution Network Sale page of Ofgem's website.[16]

Document	**Date**
77/03 - National Grid Transco – Potential sale of network distribution businesses – Consultation document	31/07/03
DN Workshop group 1 slides	18/09/03
DN Workshop group 2 slides	18/09/03
DN Workshop group 3 slides	18/09/03
170/03 - National Grid Transco – Potential sale of network distribution businesses: Next steps	17/12/03
Regulatory Impact Assessment - Potential Sale of Network Distribution Businesses, prepared by National Grid Transco	17/12/03
AWG 1 - Agenda	20/01/04
AWG 1- Minutes	20/01/04
AWG 1 - Summary of Actions	20/01/04
AWG 1 - Transco presentation – Agency proposals	20/01/04
AWG 1 - Terms of Reference	20/01/04
Development and Implementation Steering Group - Terms of Reference	20/01/04
DISG 1 - Agenda	20/01/04
DISG 1 - Minutes	20/01/04
DISG 1 - Draft Issues Log	20/01/04
Regulatory Architecture Work Group – Terms of Reference	23/01/04
Commercial Interfaces Working Group – Terms of Reference	26/01/04
CIWG 1 - Agenda	27/01/04
CIWG 1 Minutes	27/01/04
CIWG 1 - Revised Terms of Reference	27/01/04

[16] http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/gasdistributionnetworksale

Document	Date
RAWG - Working Documents	27/01/04
RAWG 1 - Agenda	27/01/04
RAWG 1 - NGT presentation offtake code CIWG meeting 1	27/01/04
RAWG 1 - NGT presentation Proposed Uniform Network Code	27/01/04
RAWG 1 - Minutes	27/01/04
AWG 2 - Agenda	28/01/04
AWG 2 - Minutes	28/01/04
AWG 2 – Shipper/Supplier Matrix	28/01/04
CIWG 1 - Agenda	28/01/04
Commercial Interface Work Group - Key Issues and Deliverables	29/01/04
NGT presentation - Offtake Code Business Rules	29/01/04
Ofgem presentation - Commercial interface work group	30/01/04
NGT presentation exit reform CIWG meeting 1	30/01/04
NGT presentation offtake code CIWG meeting 1	30/01/04
DISG 2 - Agenda	03/02/04
DISG 2 - Minutes	03/02/04
DISG 2 - NGT paper - Gas Emergencies and major loss of supply	03/02/04
DISG 2 - PowerGen paper - Lessons from BETTA	03/02/04
AWG 3 - Minutes	06/02/04
AWG 3 - Agenda	06/02/04
AWG 4 - Agenda	13/02/04
AWG 4 - Minutes	13/02/04
RAWG 2 - Agenda	17/02/04
RAWG 2 – Transco paper Proposed Framework for NGT's Post-DN Sale GT Licence	17/02/04
RAWG 2 – Ofgem presentation Roles and responsibilities of DN owners	17/02/04
RAWG 2 - Transco paper - System Operation Managed Service Agreement	17/02/04
RAWG 2 - Draft forward work plan	17/02/04
RAWG 2 - Categorised issues log	17/02/04
RAWG 2 - Minutes	17/02/04
DISG 3 - Agenda	17/02/04
DISG 3 - Ofgem presentation - Roles and responsibilities of DN owners	17/02/04
DISG 3 - NGT presentation on metering	17/02/04
DISG 3 - NGT paper on SOMSAs	17/02/04
DISG 3 - NGT paper on connections	17/02/04

Document	Date
DISG 3 - SSE alternative model	17/02/04
DISG 3 - SO Responsibilities and Contracting Framework	17/02/04
DISG 3 - Minutes	17/02/04
CIWG 2 - Ofgem Presentation - Role and responsibilities of DN	18/02/04
CIWG 2 - Minutes	18/02/04
AWG 5 - Agenda	20/02/04
AWG 5 - Agent Workgroup Draft Work Programme Overview	20/02/04
AWG 5 - Risk Log	20/02/04
AWG 5 - Reporting matrix	20/02/04
AWG 5 - Operational matrix	20/02/04
AWG 5 - Settlement and energy matrix	20/02/04
DISG 4 - Agenda	24/02/04
DISG 4 - DN Disposal, System Operation Responsibilities & Contracting Framework Exploration of Options 1 & 3	24/02/04
DISG 4 - Minutes	24/02/04
DISG 4 - NGT and SSE joint paper Comparison of Options 1 & 3	24/02/04
DISG 4 - NGT Paper - Separation of NTS and DNs	24/02/04
DISG 4 - MEUC Comments on NGT Separation paper	24/02/04
RAWG 3 - Agenda	24/02/04
RAWG 3 - Minutes	24/02/04
AWG 6 - Agenda	27/02/04
AWG 6 - Minutes	27/02/04
AWG 6 - Summary of Actions	27/02/04
AWG 6 - Agency Mitigation Matrix	27/02/04
NGT UNC discussion document	01/03/04
SSE Comments on NGT UNC Paper	01/03/04
BGT Comments on NGT's UNC Paper	01/03/04
NGT's proposed offtake code business rules	01/03/04
BGT Comments on NGT offtake code paper	01/03/04
DISG 5 - Agenda	02/03/04
DISG 5 - Minutes	02/03/04
DISG 5 - NGT Agency Presentation	02/03/04
DISG 5 - Ofgem Agency Presentation	02/03/04
RAWG 4 - Agenda	02/03/04
RAWG 4 - Development of UNC - Analysis of Change	02/03/04

Document	Date
RAWG 5 - Agenda	02/03/04
CIWG 3 - Agenda	03/03/04
CIWG 3 - Minutes	03/03/04
CIWG 3 - NGT Presentation - Shrinkage, CV and Gas Quality	03/03/04
CIWG 3 - NGT Presentation - DN Exit Capacity Substitutability	03/03/04
CIWG 3 - Ofgem Presentation - Exit and Interruption Arrangements	03/03/04
DISG 6 - Agenda	09/03/04
DISG 6 - Minutes	09/03/04
DISG 6 - NGT Presentation - SO responsibilities and Contracting Framework Presentation	09/03/04
DISG 6 - NGT - Issues addressed by the financial ring fence and other non-discrimination licence conditions	09/03/04
DISG 6 - Ofgem Presentation - Options for interfaces between shippers and network owners following potential sale of DNs	09/03/04
DISG 6 - PowerGen Presentation - Costs versus benefits – a shipper view	09/03/04
DISG 6 - AEP/Gas Forum/MEUC Paper - Common position in respect of a potential sale of a gas distribution network	09/03/04
DISG 6 - Ofgem Update on the Way Forward	09/03/04
DISG 6 - NGT Paper - SO responsibilities and Contracting Framework Presentation	09/03/04
Open letter on Gas Distribution Price Controls	16/03/04
CIWG 4 - Agenda	17/03/04
CIWG 4 - Minutes	17/03/04
CIWG 4 - Ofgem Presentation on Exit Option B	17/03/04
DISG 7 - Agenda	23/03/04
DISG 7 Minutes	23/03/04
DISG 7 - Ofgem Presentation - Options for Scope of Agency	23/03/04
DISG 7 - NGT paper Additional systems and process information	23/03/04
AWG 7 - Agenda	26/03/04
AWG 7 – Minutes	26/03/04
AWG 7 – Summary of Actions	26/03/04
AWG 7 – Shipper/Supplier Matrix - Mitigating Actions	26/03/04
CIWG 5 - Agenda	31/03/04
CIWG 5 - Minutes	31/03/04
CIWG 5 - Ofgem Presentation on Exit and Interruption Arrangements Option C	31/03/04
CIWG 5 - Ofgem Presentation Options for Agency and Governance	31/03/04

Document	Date
Arrangements	
CIWG 5 - Ofgem Presentation Initial views for scope of Agency	31/03/04
CIWG 5 - Joint Industry Paper Further Options for Exit Reform	31/03/04
CIWG 6 - Agenda	14/04/04
CIWG 6 - NGT Paper on Offtake Rights and Diurnal Storage	14/04/04
CIWG 6 - Minutes	14/04/04
RIA on Options for Exit Reform Industry letter	20/04/04
84/04 - National Grid Transco – Potential sale of network distribution businesses Allocations of roles and responsibilities between transmission and distribution networks - Regulatory Impact Assessment	20/04/04
83/04 - National Grid Transco – Potential sale of network distribution businesses Agency and governance arrangements Regulatory Impact Assessment	20/04/04
DISG 8 - Agenda	20/04/04
DISG 8 - Minutes	20/04/04
DISG 8 - NGT note for the DISG on SOMSA	20/04/04
DISG 8 - Ofgem Presentation on Allocation of Roles and Responsibilities RIA	20/04/04
DISG 8 - Ofgem Presentation Agency & Governance RIA	20/04/04
DISG 8 Issues Log	20/04/04
DISG 6/DISG 8 - NGT Paper current ring fencing licence conditions	20/04/04
CIWG 7 - Agenda	28/04/04
CIWG 7 - Ofgem Presentation on the Offtake Code	28/04/04
CIWG 7 - Ofgem Presentation on Exit Summary of Options	28/04/04
CIWG 7 - Minutes	28/04/04
DISG 9 – Agenda	04/05/04
DISG 9 - NGT Paper on UNC Governance	04/05/04
DISG 9 - NGT Paper on UNC Modification Rules	04/05/04
DISG 9 - NGT Presentation on The Agency Proposition	04/05/04
DISG 9 - Ofgem Presentation on Exit Summary of Options	04/05/04
DISG 9 - Ofgem Presentation on the Offtake Code	04/05/04
DISG 9 - Note on SOMSA Miscellaneous and Ancillary Services	04/05/04
DISG 9 - Minutes 4/5/04	04/05/04
DISG 10 - Agenda	12/05/04
DISG 10 - NGT Paper on Information Flows	12/05/04
DISG 10 - NGT Paper on Unmetered Inter-LDZ Transfer	12/05/04

Document	Date
DISG 10 - Ofgem Paper on Rebased Agency Chart	12/05/04
DISG 10 - PowerGen paper on Governance a Shippers View	12/05/04
DISG 10 - Ofgem presentation on Offtake	12/05/04
CIWG 8 - Agenda	12/05/04
CIWG 8 - presentation on NTS offtake arrangements - Discussion of options	12/05/04
CIWG 8 - Minutes	12/05/04
AWG 8 - Agenda	25/05/04
AWG 8 - Minutes	25/05/04
AWG 8 - Summary of Actions	25/05/04
CIWG 9 - Agenda	26/05/04
CIWG 9 - Glenton Bruce and EDF presentation CIWG 9 DN Booking Model	26/05/04
CIWG 9 - Statoil presentation Shippers view of option 3	26/05/04
CIWG 9 - NGT paper from DISG 10 on Information Flows	26/05/04
CIWG 9 - MEUC paper on Exit Transitional Arrangements	26/05/04
CIWG 9 - MEUC presentation on Exit Transitional Arrangements	26/05/04
CIWG 9 - NGT paper Decision making under SOMSA	26/05/04
CIWG 9 - NGT response to Waters Wye	26/05/04
CIWG 9 - NGT paper from DISG 10 on unmetered inter-LDZ transfers	26/05/04
CIWG 9 - Minutes	26/05/04
120/04 - National Grid Transco – Potential sale of gas network distribution businesses - Agency and governance arrangements	28/05/04
119/04 - National Grid Transco – potential sale of gas distribution network businesses - Allocation of roles and responsibilities between transmission and distribution networks	28/05/04
DISG 11 - Agenda	08/06/04
DISG 11 - Energywatch papers on UNC relevant objectives	08/06/04
DISG 11 - NGT paper on UNC relevant objectives	08/06/04
DISG 11 - Waters Wye paper on ownership of the Agency	08/06/04
DISG 11 - Waters Wye Paper - Comments on actions arising from the RAWG papers	08/06/04
DISG 11 - NGT response to Waters Wye from CIWG 9	08/06/04
DISG 11 - Presentation on Agency and Governance Decision	08/06/04
DISG 11 - Ofgem Presentation on Agency Workgroup Update	08/06/04
DISG 11 - Ofgem Presentation on R&R Decision	08/06/04
DISG 11 - Minutes	08/06/04

Document	Date
131/04 - National Grid Transco – Potential sale of gas distribution network businesses: Offtake arrangements	11/06/04
AWG 9 -Agenda	14/06/04
AWG 9 - Minutes	14/06/04
AWG 9 - Summary of Actions	14/06/04
AWG 9 – Revised Terms of Reference	14/06/04
CIWG 10 - Agenda	16/06/04
CIWG 10 - NGT paper further note on Inter-LDZ Transfers	16/06/04
CIWG 10 - NGT Paper Response on SOMSAs	16/06/04
CIWG 10 - Ofgem Presentation on Offtake Arrangements RIA	16/06/04
CIWG 10 - Minutes	16/06/04
DISG 12 - Agenda	22/06/04
DISG 12 - NGT Paper on Governance Entity	22/06/04
DISG 12 - NGT Paper on Structural Separation	22/06/04
DISG 12 - NGT Paper on UNC Governance	22/06/04
DISG 12 - PowerGen Paper on Further thoughts on UNC Governance	22/06/04
DISG 12 - Minutes	22/06/04
SPAWG 10 - Agenda	28/06/04
SPAWG 10 - Minutes	28/06/04
SPAWG 10 - Summary of Actions	28/06/04
SPAWG 10 - SPAWG Work Programme Overview	28/06/04
SPAWG 10 – Revised Terms of Reference	28/06/04
146/04 - National Grid Transco – Potential sale of gas distribution network businesses Interruptions arrangements: Regulatory impact assessment	30/06/04
DISG 13 - Agenda	06/07/04
DISG 13 - NGT Paper - Agency ungoverned Services Paper	06/07/04
DISG 13 - NGT Paper - Agency ungoverned services Matrix	06/07/04
DISG 13 - NGT Paper - Constitution of the UNC GT Joint Office	06/07/04
DISG 13 - NGT Paper - Gas Supply Emergencies and Gas Escapes	06/07/04
DISG 13 - NGT Paper - Options for the Governance of Agency	06/07/04
DISG 13 - Ofgem Paper - Future Agendas	06/07/04
DISG 13 - Ofgem Paper - Ofgem's position on Merger Tax	06/07/04
DISG 13 - Ofgem Presentation - Licensing Framework	06/07/04
DISG 13 - AIGT Paper	06/07/04
DISG 13 - Centrica Paper	06/07/04

Document	Date
DISG 13 - SSE Paper	06/07/04
DISG 13 Minutes	06/07/04
CIWG 11 - Agenda	07/07/04
CIWG 11 - NGT Paper on Connection Facilities and Telemetry Arrangements	07/07/04
CIWG 11 - NGT Paper on Maintenance	07/07/04
CIWG 11 - Ofgem Presentation on Interruptions RIA	07/07/04
CIWG 11 - Ofgem Presentation on SOMSAs	07/07/04
CIWG 11 - Ofgem questions for CIWG 11	07/07/04
CIWG 11 - Ofgem Paper Future Agendas	07/07/04
SPAWG 11 - Agenda	12/07/04
SPAWG 11 - Minutes	12/07/04
SPAWG 11 - Summary of Actions	12/07/04
SPAWG 11 – Draft SPAWG report to DISG	12/07/04
CIWG 12 - Agenda	14/07/04
CIWG 12 - NGT Paper on Connection Facilities and Telemetry Arrangements	14/07/04
CIWG 12 - NGT Paper on Maintenance	14/07/04
CIWG 12 - NGT paper on Measurement Arrangements	14/07/04
CIWG 12 - NGT paper on Quality Arrangements	14/07/04
CIWG 12 - Ofgem Presentation Cost of Transitional Measures	14/07/04
CIWG 12 - Minutes	14/07/04
Open letter: Timetable for Potential Gas Distribution Network Sales Project	16/07/04
DISG 14 - Agenda	20/07/04
DISG 14 - NGT Paper on xoserve Escalation Process	20/07/04
DISG 14 - NGT slide on Escalation Route	20/07/04
DISG 14 - Elexon paper on Estimate of Governance Entity costs	20/07/04
DISG 14 - E.ON comments	20/07/04
DISG 14 - NGT paper on UNC Modification Rule	20/07/04
DISG 14 - NGT Paper on UNC structures and process	20/07/04
DISG 14 - Ofgem Presentation on Governance of the Agency	20/07/04
DISG 14 - Ofgem presentation on Pensions	20/07/04
DISG 14 - Ofgem Presentation on SOMSA slides	20/07/04
DISG 14 - Ofgem presentation on indicative timetable	20/07/04
DISG 14 - Minutes	20/07/04

Document	Date
Open Letter on Environmental Liabilities	23/07/04
CIWG 13 - Agenda	28/07/04
CIWG 13 - NGT Paper on Exchange Information	28/07/04
CIWG 13 - NGT Presentation on Exit Reform	28/07/04
CIWG 13 - NGT Paper on DN-DN Operator relationship	28/07/04
CIWG 13 - NGT Paper Offtake Code Measurement CV Issues	28/07/04
CIWG 13 - Issues Log	28/07/04
Ofgem Position Paper on Pensions	02/08/04
DISG 15 - Agenda	03/08/04
DISG 15 - NGT paper on business rules for credit arrangement	03/08/04
DISG 15 - Ofgem presentation on circulation of data pro forma	03/08/04
DISG 15 - Ofgem position paper on Governance of Charging Methodologies	03/08/04
DISG 15 - Ofgem Presentation on Charging Methodology	03/08/04
DISG 15 - Ofgem paper on position of UNC Governance Arrangements	03/08/04
DISG 15 - NGT paper on current price control treatment of shrinkage	03/08/04
DISG 15 - Ofgem paper on Pensions	03/08/04
DISG 15 - Issues Log	03/08/04
DISG 15 - Minutes	03/08/04
Open letter to NGT, potential DN purchasers and other parties on License Amendment Process	05/08/04
Open Letter on Special Condition 18	06/08/04
Ofgem Position on Pensions – Supplement	09/08/04
199/04 - Offtake Arrangements, Conclusions document on framework	13/08/04
198/04 - Interruptions Arrangements, Conclusions document on framework	13/08/04
DISG 16 - Agenda	17/08/04
DISG 16 - Note from the SPAWG	17/08/04
DISG 16 - SPA Workgroup paper	17/08/04
DISG 16 - SPA Workgroup presentation on Matrix Analysis and Impact on DN Sales	17/08/04
DISG 16 - NGT work plan in relation to SPAWG recommendations	17/08/04
DISG 16 - Agency Workgroup Service Lines	17/08/04
DISG 16 - SPAWG paper Xoserve User Group Arrangements	17/08/04
DISG 16 - Ofgem presentation on NTS business separation	17/08/04
DISG 16 - Ofgem presentation on RDN-RDN business separation	17/08/04
DISG 16 - NGT presentation on ownership and governance of the Agency	17/08/04

Document	Date
DISG 16 - NGT Paper on Handling Emergencies	17/08/04
DISG 16 - NGT Paper on the title to Gas within the Network	17/08/04
DISG 16 - NGT Paper on DN Boundaries	17/08/04
DISG 16 - Ofgem presentation on Final RIA: Pro-forma Questionnaire	17/08/04
DISG 16 - Ofgem Presentation on Offtake Arrangements	17/08/04
DISG 16 - Ofgem Presentation on Interruptions Arrangements	17/08/04
DISG 16 - NGT draft letter to the Industry to Initiate UNC development process	17/08/04
DISG 16 - NGT Paper UNC Business rule process tracker	17/08/04
DISG 16 - NGT Paper on NWC Planner	17/08/04
DISG 16 - Minutes	17/08/04
Ofgem Preliminary position on the Business Separation requirements to apply between Distribution Networks	20/08/04
DISG 17 - Agenda	24/08/04
DISG 17 - Ofgem presentation on Diurnal Storage	24/08/04
DISG 17 – Ofgem preliminary position on duration of Incentive schemes	24/08/04
DISG 17 - Ofgem presentation on Rights of Appeal under UNC Governance Arrangements	24/08/04
DISG 17 - Transco paper on the constitution and structure of the GT joint office	24/08/04
DISG 17 - Transco presentation on UNC/offtake arrangements legal framework	24/08/04
DISG 17 - Ofgem paper on Asset Risk Management survey	24/08/04
DISG 17 - Ancillary Documents from DISG 16 - Tabled Document	24/08/04
DISG 17 - Centrica paper on Retrospective reconciliation - Tabled Document	24/08/04
DISG 17 - NGT paper on offtake code status - Tabled Document	24/08/04
DISG 17 - NGT paper on Offtake Code Status Appendix 1 - Tabled Document	24/08/04
DISG 17 - NGT paper on Offtake code status Appendix 2 - Tabled Document	24/08/04
DISG 17 - NGT paper on Offtake Code Status Appendix 3 - Tabled Document	24/08/04
DISG 17 - NGT paper on DN-DN flows - Tabled Document	24/08/04
DISG 17 - Shrinkage Gas Arrangements - Tabled Document	24/08/04
DISG 17 - Minutes	24/08/04
Correction - DN Sales Open Letter on Special Condition 18	26/08/04
215/04 - National Grid Transco – Potential sale of gas distribution network	02/09/04

Document	Date
businesses Initial thoughts on restructuring of Transco plc's Gas Transporter Licences	
Transco Gas Transporter Licence	02/09/04
DISG 18 - Agenda	07/09/04
DISG 18 - Ofgem presentation on Licence Arrangements	07/09/04
DISG 18 - NGT presentation on Gas Safety Cases and Emergency Response	07/09/04
DISG 18 - NGT response to DISG paper on Transportation Charges from Centrica	07/09/04
DISG 18 - SSE comments on Offtake Code	07/09/04
DISG 18 - SSE comments on Offtake and Flexibility Arrangements	07/09/04
DISG 18 - Statoil comments on the Offtake Code	07/09/04
DISG 18 - NGT presentation on Diurnal Storage	07/09/04
DISG 18 - NGT presentation on the UNC Governance Forum	07/09/04
DISG 19 – Agenda	14/09/04
DISG 19 - Ofgem presentation on Licence Arrangements	14/09/04
DISG 19 - Future DISG Agendas 14/9 - 12/10	14/09/04
DISG 19 - Minutes	14/09/04
National Grid Transco - Potential sale of Gas Distribution network business - Publication of NGT's initial drafting of proposed new NTS/GT Licence	15/09/04
Attachment 1 - Standard conditions for GTs	15/09/04
Attachment 2 - Draft special conditions NTS GT licence	15/09/04
Attachment 3 - Draft revenue restriction condition NTS GT licence	15/09/04
Attachment 4 - Standard conditions for GTs	15/09/04
Attachment 5 - Draft special conditions DN GT licence	15/09/04
Attachment 6 - Draft revenue restriction condition DN GT Licence	15/09/04
DISG 20 - Agenda	21/09/04
DISG 20 - Transco presentation - System Entry Points connected directly into the DNs	21/09/04
DISG 20 - Transco presentation - CV FWA Capping losses – securing co-operation	21/09/04
DISG 20 - Transco presentation - LNG Storage – Operational and Commercial Arrangements	21/09/04
DISG 20 - Transco presentation - Network sales – new licence conditions	21/09/04
DISG 20 - Transco paper - List of Licence Modifications and new licence conditions required as part of the section 8AA modification process	21/09/04
DISG 20 - Minutes	21/09/04
SPAWG 13 – Agenda	4/10/04

Document	Date
SPAWG 13 – Minutes	4/10/04
SPAWG 13 – Summary of Actions	4/10/04
SPAWG 13 – Transco Matrix - Network Code Ancillary Documents	4/10/04
SPAWG 13 – Transco SPAWG work plan - revised	4/10/04
Gas Distribution Price Controls - Further Clarification	06/10/04
DISG 21 - Agenda	12/10/04
DISG 21 - Ofgem presentation on Grant of Licence Consultation	12/10/04
DISG 21 - Ofgem presentation on responses to the Licence Conditions	12/10/04
DISG 21 - Transco paper on Option C	12/10/04
DISG 21 - Transco presentation on Option C	12/10/04
DISG 21 - Transco xoserve Services Document	12/10/04
238/04 - Open letter: Updated timetable for Potential Gas Distribution Network Sales Project	15/10/04
Ofgem Note on initial draft of private CLM licence condition	19/10/04
Ofgem initial drafting of private CLM licence condition	19/10/04
DISG 22 - Agenda	19/10/04
DISG 22 - Transco presentation on Transition from Network Code to UNC	19/10/04
DISG 22 - Ofgem Presentation on Private CLM	19/10/04
DISG 22 - Transco paper on Amended Standard Condition 4	19/10/04
DISG 22 - Transco paper on Amended Standard Condition 4A	19/10/04
DISG 22 - Transco paper on Amended Standard Condition 9 - NTS re Network Code	19/10/04
DISG 22 - Transco paper on Amended Standard Condition 9 - Network Code Condition	19/10/04
DISG 22 - Transco paper on Amended Standard Condition 9 - Joint Governance	19/10/04
DISG 22 - Transco paper on Amended Standard Condition 9 - UNC/NC	19/10/04
DISG 22 - Transco presentation on cash flow under the proposed Offtake Arrangements	19/10/04
DISG 22 - Transco timeline	19/10/04
DISG 23 - Agenda	26/10/04
DISG 23 - NGT presentation on NTS Exit Capacity Zonal/Nodal Models	26/10/04
DISG 23 - NGT paper on NTS Exit Capacity Zonal/Nodal Models	26/10/04
DISG 23 - Transco presentation on Customer Safeguards under Transco Agency governance arrangements	26/10/04
DISG 23 - NGT presentation on Xoserve voting arrangements	26/10/04
DISG 23 - Transco papers on CV Methodologies	26/10/04

Document	Date
DISG 23 - Special Condition B Licensee's procurement and use of system management service (DN's)	26/10/04
DISG 23 - Special Condition B Licensee's procurement and use of system management service (NTS)	26/10/04
DISG 23 - Special Condition B Permitted procurement activities (NTS)	26/10/04
DISG 23 - Standard Special Condition A prohibited procurement activities (NTS and DN constraints)	26/10/04
DISG 23 - Note from E.ON	26/10/04
DISG 24 - Agenda	02/11/04
DISG 24 - Transco presentation on NTS exit capacity definition - Temporal consideration	02/11/04
DISG 24 - Transco presentation on flow flexibility	02/11/04
DISG 24 - Standard Condition B Amendments to Standard Conditions and Standard Special Conditions applicable to the licensee (NTS)	02/11/04
DISG 24 - Standard Condition A Amendments to Standard Conditions and Standard Special Conditions applicable to the licensee (DNs)	02/11/04
DISG 24 - Standard Special Condition A General obligations in respect of gas transporters' pipe-line systems	02/11/04
Joint Ofgem and DTI open letter - Sale of NGT's Local Gas Distribution Networks (DNs): Issue of an exemption from a shippers licence	04/11/04
Form of five new additional GT licences granted to Transco plc on 5 November 2004	05/11/04
Transco plc - Notice of the grant of five new additional gas transporter licences	05/11/04
DISG 25 – Minutes	09/11/04
DISG 26 – Agenda	16/11/04
DISG 26 – NGT paper Exit Regime Timetable	16/11/04
DISG 26 – Ofgem presentation Legal separation between Transco's NTS and RDN businesses	16/11/04
DISG 26 – NGT presentation UNC termination process	16/11/04
DISG 26 – NGT paper Commercial Framework – UNC & NTS/DN operator arrangements	16/11/04
DISG 26 – NGT initial drafting Standard Special Condition Long Term Development Statement (DN only)	16/11/04
DISG 26 - NGT initial drafting Standard Special Condition Long Term Development Statement (NTS only)	16/11/04
DISG 26 - NGT initial drafting Standard Special Condition First line emergency response service to the operator of the NTS	16/11/04
DISG 26 – s8AA licence drafting issues list v2	16/11/04

Document	Date
DISG 26 – Ofgem initial drafting Standard Special Condition Distribution Network Incentive Scheme and Performance Reporting	16/11/04

3.3 In addition, workgroup participants have submitted comments (generally in email form) in relation to issues discussed during workgroups. These comments have not been listed in this Appendix. Ofgem welcomes views on whether this list is complete.

3.4 In relation to any of these documents which were issued by Ofgem, it was made clear that there could be no expectation on the part of Transco, potential DN purchasers or any other interested parties either as to what the Authority's final decision in relation to the proposed DN sales may be, or as to the regulatory framework which may be implemented if the Authority consents to the proposal. These documents issued by Ofgem were provided on an informal basis and should not be treated as binding on the Authority, nothing in these documents is to be construed as granting any rights or imposing any obligations on the Authority. The Authority's discretion in this matter will not be fettered by any statement made in these documents.

Appendix 4 Respondents to consultation documents

4.1 This appendix lists all of the respondents to each consultation document published by Ofgem as part of the DN sales process. For completeness, the number of confidential responses to each document is also noted.

- **July 2003 Consultation Document respondents:**
  - Association of Electricity Producers
  - BP Energy
  - British Gas Connections
  - British Gas Trading
  - ConocoPhillips
  - Contract Natural Gas
  - Corus
  - EDF Energy
  - Elexon
  - ENI UK
  - Entergy-Koch Trading
  - Gas Forum
  - Gaz de France
  - Gemserv
  - Glenton Bruce
  - GMB (trade union)
  - Health & Safety Executive
  - Hydro Polymers Limited
  - RWE Innogy
  - Major Energy Users Council
  - National Grid Transco
  - Noel Copperthwaite Associates
  - PowerGen
  - SBGI
  - Scottish Power
  - Shell Gas Direct

- SP Gas
- SSE
- Statoil
- Terra Nitrogen
- Total Gas & Power
- *2 confidential responses*

♦ **Roles & Responsibilities RIA respondents**

- Association of Electricity Producers
- BP Energy
- British Gas Trading
- EDF Energy
- Energywatch
- National Grid Transco
- PowerGen
- RWE Innogy
- Shell Gas Direct
- Statoil
- United Utilities
- *5 confidential responses*

♦ **Agency & Governance RIA respondents**

- Association of Electricity Producers
- BP Energy
- British Gas Trading
- EDF Energy
- Electralink
- Energywatch
- Gemserv
- National Grid Transco
- PowerGen
- RWE Innogy
- Shell Gas Direct
- SSE
- Statoil
- Total Gas & Power

- United Utilities
- *4 confidential responses*

♦ **Offtake Arrangements RIA respondents**

- Association of Electricity Producers
- BP Energy
- British Gas Trading
- EDF Energy
- E.ON UK
- Gemserv
- Health & Safety Executive
- National Grid Transco
- RWE Innogy
- Shell Gas Direct
- SSE
- Statoil
- Total Gas & Power
- *2 confidential responses*

♦ **Interruptions RIA respondents**

- Association of Electricity Producers
- BOC
- BP Energy
- British Gas Trading
- Chemical Industries Association
- Corus
- EDF Energy
- E.ON UK
- Health & Safety Executive
- Major Energy Users Council
- National Grid Transco
- RWE Innogy
- Scottish Power
- Shell Gas Direct
- SSE
- Statoil

- Total Gas & Power Limited
- United Utilities
- *1 confidential response*

♦ **Licence Grant Consultation respondents**

- British Gas Connections
- ESP Networks
- SSE
- Utility Grid Installations Limited
- *3 confidential responses*

♦ **Initial Consultation on restructuring of Transco's Licence respondents**

- BP Energy
- British Gas Trading
- British Gas Connections
- EDF Energy
- E.ON UK
- ESP
- Gas Industry Safety Group
- MGN Gas Networks
- National Grid Transco
- RWE Innogy
- Scottish Power
- SSE
- Statoil
- United Utilities
- *3 confidential responses*

4.2 In addition, interested parties have submitted comments (generally in email form) in relation to issues discussed during workgroups. These comments have not been listed in this Appendix. Ofgem welcomes views on whether this list is complete.

Appendix 5 A day in the life

5.1 The new regulatory, commercial and operational arrangements that are proposed to be implemented in the event of DN sales proceeding have been specifically designed in connection with NGT's proposed transaction, to protect the interests of existing and future customers whilst limiting the amount of disruption that is felt by the wider industry. Despite this, industry participants will see changes occurring in some aspects of the process of arranging for the offtake of gas from the NTS. The purpose of this appendix is to draw together the proposals relating to reform of offtake arrangements, interruptions arrangements and agency and governance, and to describe ways in which it is envisaged a variety of industry participants are likely to interact with the new proposed arrangements. The descriptions set out in this appendix are merely how Ofgem envisages the situation in relation to certain participants and is not intended to be conclusive.

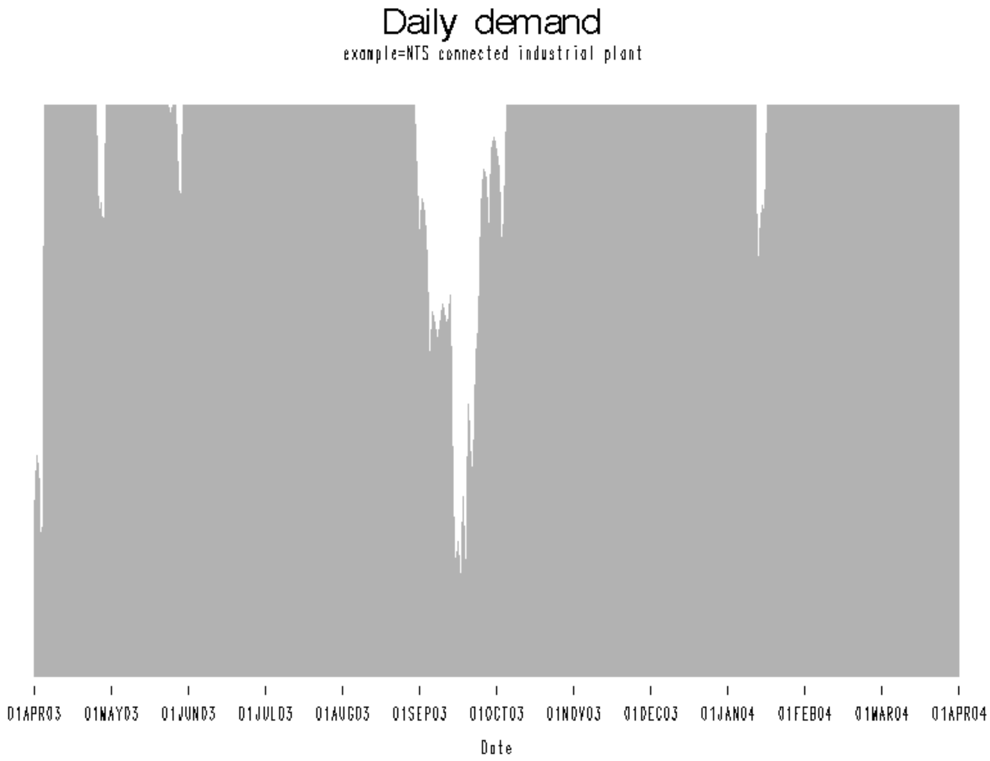
5.2 The types of industry participants included in this appendix have been selected to reflect a broad cross-section of the industry. They are:

- NTS connected industrial plants (e.g. chemical plants);
- NTS connected gas fired power stations;
- Interconnectors and storage sites;
- DNs; and
- DN connected customers.

NTS connected industrial plant

5.3 Typically, NTS connected industrial plants (e.g. chemical plants) have predictable offtake profiles that are relatively "flat", both within-day and across the year. NGT has provided an example of a typical offtake profile for customers such as these (based upon real offtake data). This is illustrated in Figure A.1 below:

Figure A.1 Offtake profile: Industrial customer



5.4 The majority of these NTS connectees require firm exit capacity, with only those that have significant onsite gas storage having the potential to offer demand management services to the NTS.

5.5 Under the proposed arrangements NTS connected industrial customers, as now, will not interact directly with the NTS in the new commercial arrangements. Instead their requirements for NTS offtake capacity will be arranged through a licensed shipper, who will contract with the NTS for its required volume of capacity rights.

Firm NTS exit capacity and offtake flexibility

5.6 Given that NTS connected industrial customers typically have predictable (and flat) long term offtake profiles, it is likely that these customers will want to satisfy the majority of their offtake capacity requirements through long term contracting (although the capacity booking decision will depend upon the expectation of prices that might arise from the various product releases plus an assessment of the potential scarcity of the products).

5.7 To the extent that NTS connected industrial customers vary their within-day rate of offtake of gas from the NTS, they will also be required to buy NTS offtake flexibility rights. However, given that the typical gas offtake profile of these participants is flat through the day, it is unlikely that this class of NTS connectee will be a major user of NTS offtake flexibility.

5.8 In the **long-term**, it is proposed that firm exit capacity and flexibility will be available for sale through an **unconstrained** allocation process. These capacity products will be made available at regulated prices (as now), hence prices will not be market determined. Through this allocation, shippers will be able to book from 3 years ahead, for up to fifteen years ahead. Accordingly, it is likely that NTS connected industrial customers will request a shipper to book long-term capacity and flexibility through this allocation process (via an external bilateral contract, or arrangement between connectee and shipper). Note that proposed credit arrangements for the long term purchase of NTS exit capacity will be the same as those currently in place at entry.

5.9 In the **medium-term** (i.e. at year ahead), it is proposed that the NTS will undertake a **constrained** allocation of any remaining available firm exit capacity and flexibility rights. To the extent that NTS industrial customers have not sufficiently contracted for NTS exit capacity and flexibility rights in the long term (and to the extent that these rights are made available), they will be able to arrange for shippers to purchase additional rights through these allocations.

5.10 It is important to note, therefore, that NTS connected industrial customers are expected to have a choice over how to procure sufficient exit capacity rights to meet their requirements. For example, if these customers do not want to undertake any medium- / short-term capacity procurement, then they will be able to purchase all of the capacity (and flexibility) rights they need in the long-term.

5.11 Depending on contracts, it is expected that shippers will also be able to adjust their holding of NTS exit holding capacity and flexibility in the medium term through trading with shippers at that offtake point, or (more likely) through trading facilitated by the NTS SO to another offtake point. Note that medium term adjustments of capacity and flexibility through either trading with other connectees, or through facilitated trading with the NTS would need to be conducted through shippers.

5.12 It is unlikely that NTS connected industrial customers will undertake significant short term contracting for offtake capacity or flexibility (i.e. at day ahead and within day).

This is because to do so may mean that these customers may find that no firm offtake capacity is available, or increase their exposure to changes in the price of capacity. However, the precise behaviours of these customers will depend upon the interaction of numerous factors, such as the volumes of firm and interruptible products available, the prices of these products and knowledge of the connectee about anticipated flow patterns.

Interruption and demand management

5.13 It is anticipated that NTS connected industrial customers will be able to offer demand management services (e.g. "turn down" contracts) to the NTS under the proposed new arrangements. These arrangements are likely to give customers more choice than they have at present, enabling them to agree contracts with the NTS of the form and content that is most appropriate to their particular circumstances (rather than having to follow a "one size fits all" approach).

5.14 The extent to which NTS connected industrial customers will be able to offer these services to the NTS and/or buy interruptible rights at the day ahead stage will depend upon whether these customers have appropriate gas storage facilities, or upon their propensity to forego production. Those customers that do have sufficient gas storage or are prepared to either cease or reduce offtake of gas may wish to arrange long term contracts for demand management services with the NTS (through shippers).

5.15 In the **short-term** (at day ahead), it is envisaged that the NTS will also offer an **interruptible product** for sale. Given that this product may well be expected to be cheaper than firm capacity (and possibly be free), some industrial customers may choose to wait until day ahead, and request a shipper to secure interruptible rights on their behalf. However, should customers follow this approach, there is a risk that rights will occasionally not be available (for example at peak). It is during these times that customers will need to utilise their gas storage facilities or cease or reduce gas offtakes.

Other activities

5.16 The proposed new arrangements are also expected to affect a range of other activities including:

- gas nominations and operations; and
- payment of transportation and balancing charges.

Gas nominations and operations

5.17 Under the proposed new arrangements, NTS connected industrial customers will continue to prepare and submit nominations at day ahead (through the submission of Offtake Profile Notices (OPNs)), and these will continue to be submitted to the Gas National Control Centre (GNCC). Under the proposed new arrangements, however, it will be the agency that will be responsible for the provision and maintenance of the AT link system (or any successor system), rather than NGT.

5.18 Flows of commercial nominations under the proposed new arrangements will also continue to be made by shippers through the AT link system, just as under the current arrangements. It will be the Agency that will have responsibility for the provision and maintenance of this system.

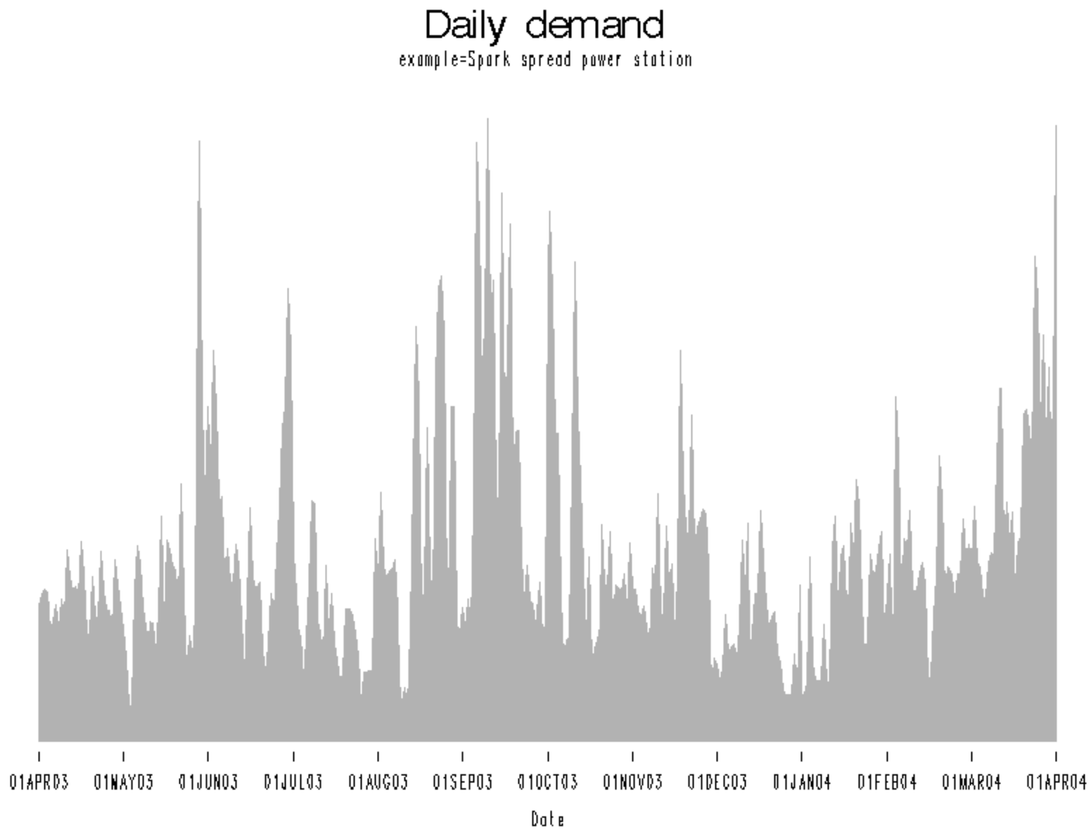
Payment of transportation and balancing charges

5.19 It is envisaged that the commercial processes through which transportation and balancing charges are settled by NTS connected industrial customers will remain largely unchanged under the proposed new arrangements (i.e. continue to receive invoices from and make payments to the shippers that arrange their capacity requirements). The main difference will be that it will be the agency that will be responsible for preparation of invoices to shippers for charges for the use of the NTS.

NTS connected gas fired power stations

5.20 Some NTS connected power stations (e.g. those that operate by responding to variations in the spark spread) offtake gas according to a profile that is more variable (both within-day and seasonal) than NTS connected industrial customers. NGT have provided an example of a typical offtake profile for power stations such as these (based upon real offtake data). This is illustrated in Figure A.2 below:

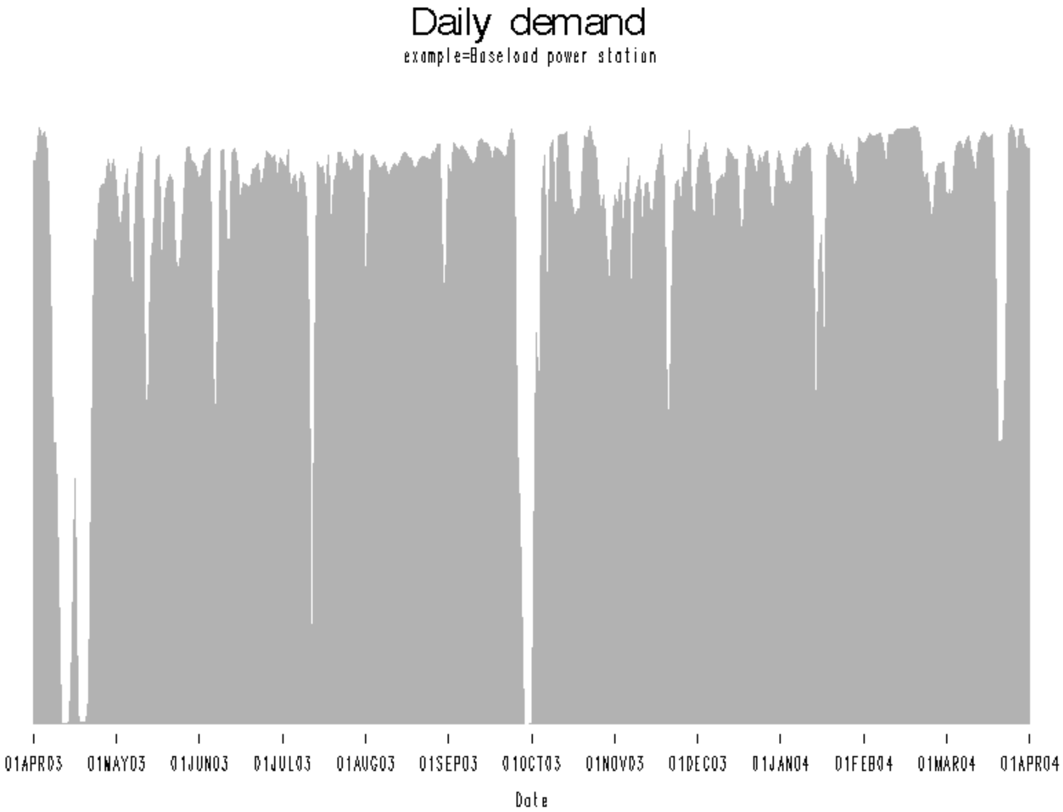
Figure A.2 Offtake profile: Power station following spark spread



5.21 Although these NTS connectees are able to purchase the same range of capacity products as other NTS connectees, they may require different combinations of the available products, and/or contract for their purchase at different times ahead of delivery. Note however that the actual capacity booking decision will depend upon the expectation of prices that might arise from the various product releases plus an assessment of the potential scarcity of the products.

5.22 In contrast, those power stations that operate according to a more "baseload" profile will be more likely to have an NTS gas offtake profile that is flat through the day. An example of a typical offtake profile for a baseload gas fired power station (again, provided by NGT) is provided below:

Figure A.3 Offtake profile: Power station run as baseload



5.23 As such, their behaviour in contracting for NTS exit capacity is likely to resemble that of NTS connected industrial customers, as described in the previous section. For the purposes of clarity, in the remainder of this section, we describe the expected day-to-day impact of the proposed arrangements on those power stations that have a more variable profile of offtake of gas from the NTS.

5.24 As with NTS connected industrial customers, NTS connected power stations will arrange their NTS exit capacity requirements through a licensed shipper.

Firm NTS exit capacity and offtake flexibility

5.25 Under the proposed new arrangements, power stations connected to the NTS are expected to be able to purchase a combination of NTS exit capacity and NTS offtake flexibility to satisfy their gas offtake requirements. This contrasts with the current arrangements where flexibility is effectively "bundled" together with the firm NTS exit capacity.

5.26 Typically, power stations will want to purchase both firm NTS exit capacity (sufficient to cover end of day offtake quantity) and NTS offtake flexibility (to cover within day variations from the flat 1/24th rate). Given that power stations are currently obliged to book MDQ based on a 24 *MHQ basis, it is possible that, depending on the price relativity of NTS exit capacity and flow flexibility products, they might want to instead meet their MHQ and offtake flow variation requirements with a combination of flexibility rights and reduced level of MDQ to minimise NTS exit product costs).

5.27 It is anticipated that power stations will be able to understand their long term requirements for NTS exit capacity and NTS offtake flexibility, and therefore arrange for the purchase of this quantity through shippers. NTS exit capacity (and flexibility) will be available for purchase through the long term allocation process for three years ahead and beyond. To ensure that they secure firm access to offtake capacity, and reduce their exposure to price risk, it is anticipated that power stations will secure NTS exit capacity and flexibility rights through this long term allocation process (through their selected shippers).

5.28 Under the proposed new arrangements, where power stations are not certain of their NTS exit capacity and flexibility requirements at three years ahead, they will be able to purchase additional exit capacity and flexibility at the year ahead stage (to the extent that it is still available). Within year, we would also expect power stations to make relatively more adjustments to holdings of NTS exit capacity and flexibility than NTS connected industrial customers (for example, in order to adjust holdings for changes in the scheduling of planned outages). Once again, these medium term adjustments would be undertaken through a chosen shipper.

Interruption and demand management

5.29 It is envisaged that power stations will still be able to offer demand management services to the NTS under the proposed new arrangements. These services may be contracted long term with power stations by shippers. In turn, shippers will then organise long term contracts for demand management services with the NTS.

5.30 As noted above, in the short term (at day ahead), the NTS will also offer an interruptible product for sale. Power stations connected to the NTS would be able to purchase this product (through a selected shipper). However to be able to mitigate the risk that capacity is not available at the day ahead stage, power stations would need to have sufficient gas storage facilities to meet their daily gas requirements or be prepared to cease generation.

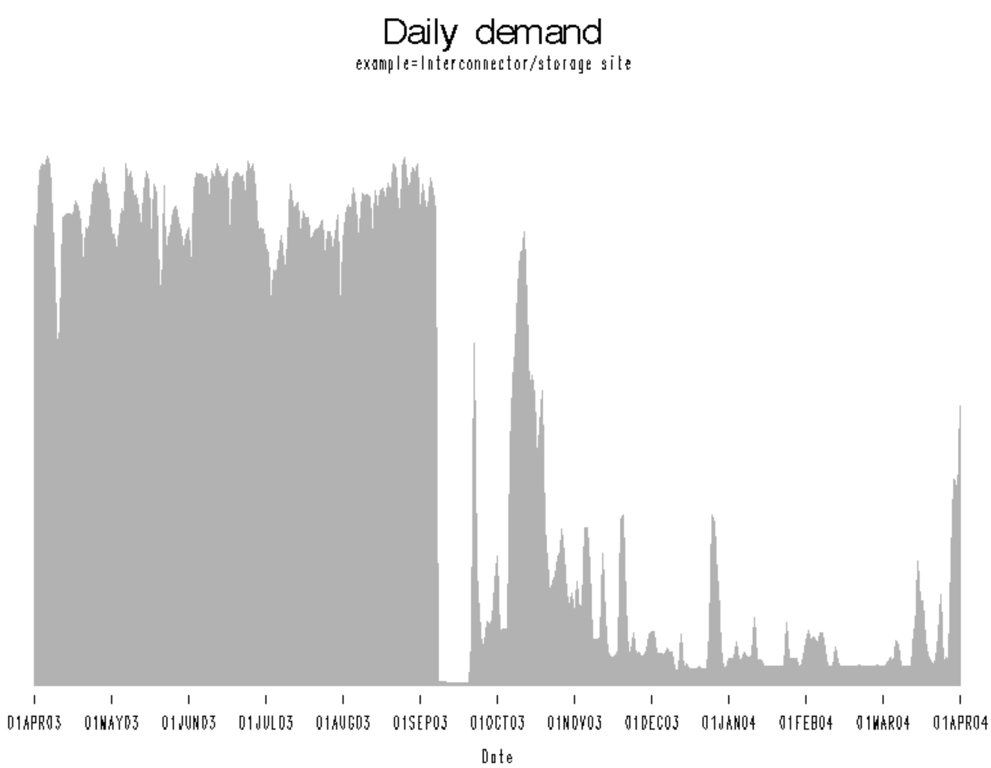
Other activities

5.31 Gas nominations and operations will follow the same process as at present (as described above). In addition, transportation and balancing charges payment will remain unchanged (i.e. with payment being made to the relevant shipper). The only difference will be that it will be the Agency that will be responsible for preparation of invoices to shippers for charges for the use of the NTS (rather than NGT).

UK-Continent interconnector and storage sites

5.32 The offtake capacity requirements for the UK-Continent interconnector and storage sites are different from those of NTS connected industrial customers and power stations. Generally speaking, this is because the interconnector and most storage sites tend to have a peak offtake requirement that is "counter-cyclical" (i.e. at times of high demand for gas from the NTS they will be likely to flow gas onto the NTS, rather than offtake it). An example of a typical offtake profile for an NTS connectee that has a "counter-cyclical" offtake profile is included in Figure A.4 below:

Figure A.4 Offtake profile: NTS connectee with counter-cyclical offtake



5.33 Accordingly, the NTS offtake products purchased by shippers on behalf of these participants (and the time at which they are procured) may differ to those of shippers of other NTS connectees.

Firm NTS exit capacity and offtake flexibility

5.34 The offtake of gas from the NTS by the UK-Continent interconnector and storage sites is typified by two key points:

- ♦ offtake is variable across seasons (and within day); and
- ♦ peak offtake from these NTS offtake points is typically at times (and seasons) when demand for NTS offtake capacity is relatively low (e.g. over summer).

5.35 As the interconnector and storage sites will therefore generally require NTS offtake capacity at off-peak times, they will be unlikely to purchase "peak" capacity through the initial allocation. Instead, these NTS connectees are likely to secure firm NTS offtake rights through a combination of:

- ♦ **purchase of day ahead firm NTS exit capacity**. To the extent that this is available, this would allow these sites to purchase rights for off-peak days during the day (and avoid the relatively high cost of offtake from the NTS associated with pricing arrangements based upon peak periods);
- ♦ **buying rights through facilitated trading**. In the nodal arrangements, the NTS will be responsible for facilitating trading between participants. Therefore, to the extent that other participants are willing to trade rights for offtake from the NTS in off-peak periods, the interconnector and storage sites may be able secure offtake rights through secondary markets; and
- ♦ **purchase of day-ahead interruptible rights**. Transco has proposed selling an interruptible product at the day ahead stage. This is discussed in more detail below.

5.36 As with the other NTS connectees described in this appendix so far, the interconnectors and storage sites will be required to arrange their holdings of NTS exit capacity and flexibility through a shipper (as now).

Interruption and demand management

5.37 As noted above, the interconnector and storage sites may want to purchase the short term interruptible product offered by the NTS SO, given the counter-cyclical nature of their offtake profiles. In addition, there may be some scope for these participants to arrange demand management services with the NTS, although the extent to which this is possible may be limited if they prefer to wait until the short term to contract for their offtake capacity requirements.

5.38 In any event, all interruption and demand management contracting that interconnectors and storage sites wish to undertake will need to be made through shippers, rather than directly with the NTS.

Other activities

5.39 Under the proposed new arrangements, as with power stations and the other NTS connectees described above, gas nominations and operations will follow the same process as at present (hence, for example, storage sites will be required to submit Storage Flow Notices at day ahead, directly into the Gas National Control Centre).

5.40 Transportation and balancing charges payment will also be the same as at present (i.e. with payment being made to the relevant shipper). The only difference from current arrangements in this regard will be that it will be the Agency that will be responsible for preparation of invoices to shippers for charges for the use of the NTS (rather than NGT).

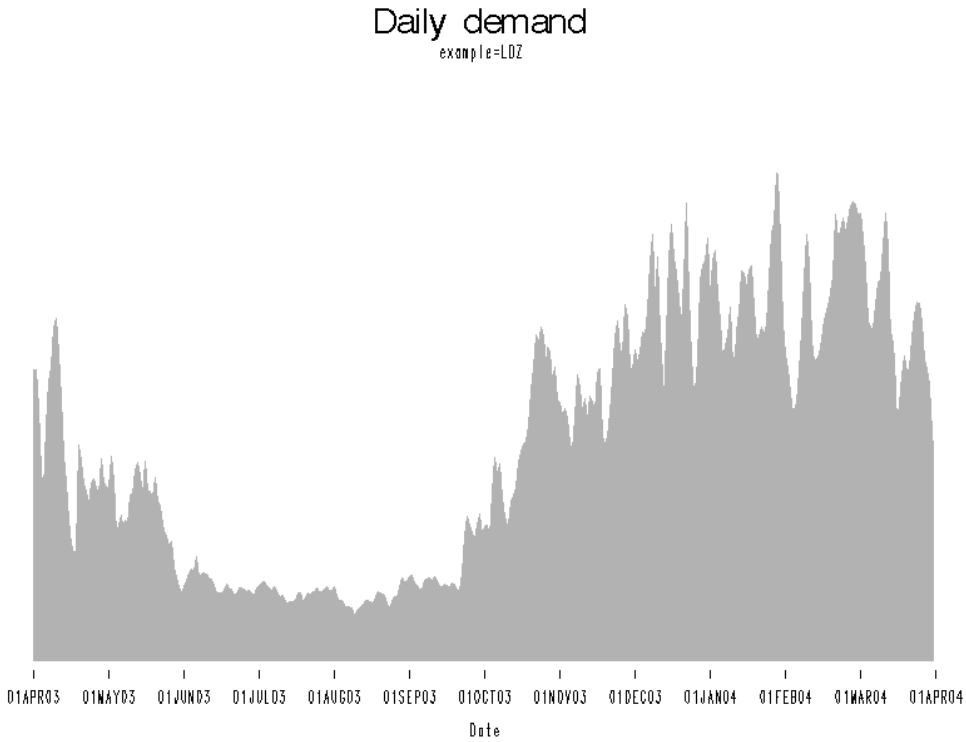
DNs

5.41 The NTS offtake profile of the DNs is significantly influenced by the volume of NDM load connected, namely that offtake:

- ♦ is seasonal through the year, peaking in winter; and
- ♦ exhibits some variability through the day (although not to the same degree that variability exists in daily offtake from the DNs).

5.42 NGT have provided an example of a typical offtake profile for an DN (based upon real LDZ offtake data). This is included in Figure A.5 below

Figure A.5 Offtake profile: DN offtake



Firm NTS exit capacity and offtake flexibility

5.43 Under the proposed new arrangements, DNs will participate directly in the long-term allocation of both NTS exit capacity and flexibility, and purchase a sufficient quantity of both of these products to enable them to satisfy the 1 in 20 security of supply standard that is placed on them through their GT licence.

5.44 DNs should face real choices between investing in their own networks, and requesting firm NTS offtake capacity and NTS offtake flexibility. This is particularly relevant in the case of investment in DN storage facilities, which is substitutable with NTS offtake flexibility. As such, DNs will be incentivised through an appropriate incentive scheme to ensure that they make an efficient trade off between investment in their own networks, requests for firm NTS offtake capacity and offtake flexibility, and interruption or demand management.

5.45 It is anticipated that the majority of the offtake capacity and flexibility requirements are likely to be met through the long term allocation process, given that it is only through the long term allocation that the NTS can receive investment signals to provide more capacity as required. In contrast, by waiting until the medium/short term to secure capacity rights, sufficient exit capacity may not be available.

5.46 Accordingly, DNs would be unlikely to leave the purchase of large volumes of either NTS exit capacity or flexibility until the medium or short term. Instead, the purchase and/or facilitated sale of NTS exit capacity and flexibility in these time periods is only likely to result from adjustments in estimates of demand.

Interruption and demand management

5.47 It is expected that the DNs may choose to contract with the NTS for demand management services, such as limited "turn down" under the proposed new arrangements.

5.48 The DNs are likely to be able to provide these services through the use of own gas storage facilities, and interruption/demand management contracts held with DN connected loads. As with NTS offtake capacity and flexibility, DNs will be able to contract directly with the NTS for the arrangement of demand management contracts.

Other activities

5.49 The separation of ownership between the NTS and DNs will mean that new processes will be defined to enable DNs to undertake the following activities:

- ♦ gas nominations and operations; and
- ♦ payment of transportation charges.

Gas nominations and operations

5.50 Under the proposed new arrangements, DNs will provide physical flow notifications via a similar mechanism to the way in which NTS directly connected customers submit Offtake Profile Notices (OPNs) at present. This data, submitted at day ahead, will be provided directly into the Gas National Control Centre.

Payment of transportation

5.51 Under the proposed new arrangements, DNs will procure NTS exit products from the NTS. The procurement will involve a cash-flow from the DNs to the NTS (that will be regarded as a "cost" to the DNs just like any other cost in future price control settlements). The aggregate allowed revenue defined by the price control will be recovered by the DNs from its customers, the shippers (representing DN connected customers).

5.52 It is anticipated that the Agency will raise transportation invoices for the DNs (using Agency systems). It will then be the responsibility of the DNs to consider the basis for how they recover charges from their customers. Assuming DNs choose to charge using the current charge item structures then the current invoicing systems (within UK-Link systems) can be used for invoicing purposes. Accordingly, the Agency would manage these systems. However, should the DNs change the manner in which charges are allocated to shippers, then current invoicing systems will need to be amended (and *in extremis* replaced).

DN connected customers

5.53 It is envisaged that customers connected to the DNs will largely be unaffected by the reforms proposed to be undertaken in connection with the sale of one or more of NGT's DNs.

Firm NTS exit capacity and flexibility

5.54 DN connectees (and their shippers) will not be permitted to purchase either NTS exit capacity or NTS offtake flexibility. Instead, DN connectees will solely be responsible for booking a level of DN exit capacity sufficient for their requirements, through the current DN exit capacity booking process via shippers.

Interruption and demand management

5.55 Interruptions (and demand management) arrangements at the DN level are not proposed to be reformed as part of the DN sales process. Accordingly, current arrangements will remain in place for DN sales go-live.

5.56 The main change for DN connectees will be that, instead of NGT being the party that will exercise interruption contracts, it will be the relevant DN. As such, under the proposed new arrangements, the NTS will not be permitted to contract directly with DN connectees for either interruption or demand management services.

Other activities

5.57 The separation of ownership between the NTS and DNs is not expected to significantly affect the process through which DN connectees either:

- nominate their flow onto the DN network; or
- pay for DN exit capacity.

Gas nominations and operations

5.58 It is envisaged that the operation of DN networks will be a responsibility of each separate DN. As such, DN connectees will follow current procedures for nominating gas flow in advance of the gas day. Operational flows of information will also continue as at present

Payment of transportation and balancing charges

5.59 Under the proposed new arrangements, DN connectees will continue to receive a single invoice for transportation charges that will state the portion of charge relating to DN transportation, and the portion relating to NTS transportation. This invoice will be settled with the relevant DN (hence, for the avoidance of doubt, DN connectees will not be required for example, to make payments to the NTS for NTS exit capacity).

Appendix 6 Review of evidence of estimated potential benefits of DN sales

6.1 In considering the potential for efficiency benefits to customers as a result of DN sales, Ofgem has considered:

- productivity studies used to inform the current electricity Distribution Price Control Review (DPCR) process;
- productivity studies used to inform Transco's main price control review;
- the arguments adopted by Ofwat as to the value of comparators;
- empirical evidence regarding economies of scale and scope; and
- current Ofgem assumptions regarding cost improvements for the National Grid Company (NGC) and Transco.

6.2 We consider each of these in turn below.

Analysis performed for the DPCR

6.3 As part of the current DPCR process, Ofgem asked Cambridge Economic Policy Associates (CEPA) to undertake a study to forecast productivity growth for the GB Electricity Distribution Network Operators (DNOs) as a sector to inform its assessment of efficiency and costs for the period 2005/6 to 2009/10[17].

6.4 Within the report CEPA considered Partial Factor Productivity (PFP) for operating expenditure, which considered historical volume adjusted trends in real unit operating expenditure as achieved by the following utility sectors:

- GB electricity distribution;
- Water and sewerage in England and Wales; and
- Electricity transmission in England and Wales.

[17] Productivity improvements in DNOs, Final Report, CEPA, November 2003

6.5 The key partial productivity factors presented for operating expenditure are summarised in Table A.3 below.

Table A.3: PFP operating expenditure derived for utilities

Sector	**PFP operating expenditure**	**Comments**
DNOs	7.7%	Trend for 1991/2 – 2001/2, includes exceptional improvement[18] in 2000/01.
England and Wales water & sewerage	5.0%	Quality adjusted figure based on customer value weighting, 1995/6 – 2001/2.
England & Wales electricity transmission (NGC)	4.9%	Trend growth for last eleven years (1990/1 – 2001/2).

6.6 As the above table shows, electricity DNOs have historically achieved significant operating expenditure reductions, with a trend of 7.7% per annum. Indeed, when compared to the growth achieved by NGC over a similar period, it can be seen that the electricity distribution sector has achieved growth of 2.8% per annum in excess of that achieved by electricity transmission. It could be argued that one of the key drivers for this differential is the presence of comparative regulation in electricity distribution. Were this differential to be applied to a no sale option assumed rate of 3%, then it is possible to draw the conclusion that an annual improvement rate of 4.7% is feasible[19].

6.7 In the England and Wales water and sewerage industry, the pace of improvement has been slightly less impressive. However, the percentage derived relates to a shorter time period, and excludes the period immediately after privatisation.

6.8 The CEPA study would therefore suggests that, in the event of DN sales, that DNs could be expected to achieve an annual rate of improvement in total operating expenditure of between 4.7% and 7.7%. Therefore, when considering the annual

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[18] If data for 2000/01 is excluded the percentage reduces to 5.8%. However, Ofgem is of the view that the 2000/01 improvement could realistically be attributed to improved productivity, in particular in response to the last price control settlement DPCR 3, and as such, is not minded to exclude data for 2000/01.

[19] Derived from 7.7% / 4.9% *3%, i.e. if the premium of electricity DNO performance relative to NGC performance is applied to a rate of 3%.

rate of improvement of *controllable* operating costs, the relevant percentages could be expected to be even higher.

Analysis performed for Transco's price control review

6.9 As part of Transco's price control review, Ofgem asked Europe Economics to undertake a top-down assessment of the scope for Transco to improve its efficiency to inform Ofgem's view of Transco's costs for the 2002 to 2007 period.

6.10 Within this study, Europe Economics performed a review of relevant academic literature and surveys. Within this review, a number of studies relating to the gas industry are quoted. Parker and Martin (1997)[20] note that better performance would have been seen in the gas industry had more attention been paid to the structure of the industry at privatisation. Furthermore, Waddams-Price and Weyman-Jones[21] find, with respect to productivity growth within the gas industry, that there was little pressure on individual regions to adopt best practice. Europe Economics concluded that:

> "the evidence on the gas industry suggests that although British Gas was privatised in 1986, some of the potential for efficiency improvements was missed initially, and that the structure of the industry played a part in slowing restructuring in the early years after privatisation".

6.11 The Europe Economics study also considered historical compound annual changes in real unit operating expenditure for Transco, but encountered difficulties in interpreting the results. They concluded that a substantial part of the cost reduction experienced by British Gas and Transco was the result of economies of scale associated with an increase in throughput. In contrast, it was observed that the same economies of scale effect did not seem to have been a significant factor for any of the other industries considered by the study.

Ofwat valuation of comparators

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[20] "The Impact of Privatisation: Ownership and Corporate Performance in the UK", London, Routledge.
[21] "Malmquist indices of productivity change in the UK gas industry before and after privatisation", Applied Economics, Volume 28, Number 1, pp29-39.

6.12 Comparators play a key role in the regulation of the water industry. In particular, Ofwat has devoted considerable effort to assessing the value of the loss of a comparator in the context of approving, or otherwise, a merger within the water industry. The studies performed in response to proposed water mergers include the following:

- Lyonnaise des Eaux / Northumbrian Water Group (1995): NERA Economic Consulting quantified the impact of the loss of a comparator by applying regulatory experience in the electricity and water industries. They concluded that the lower bound of the present value of the detriment from losing a single comparator could range from £100 million to £350 million, depending on the specific assumptions selected. The Director General of Water Services (DGWS) said that the loss of Northumbrian as a separate comparator would seriously prejudice his ability to make comparisons and would therefore weaken the effectiveness of the regulatory system[22]. The result was that Lyonnaise gave assurances that prices would be reduced by 15% to all customers of the combined water businesses over the next six years to reflect the loss of a comparator.

- Severn Trent / South West Water and Wessex Water / South West Water (1996): Two companies (Severn Trent and Wessex Water) sought to merge with South West Water Services (SWWS) in 1996. The final Competition Commission ruling[23] stated that "the loss of SWWS as a comparator would seriously prejudice the DGWS's ability to make comparisons between different water enterprises", though it added that it did not think that this loss could be reliably quantified. The Competition Commission concluded that no recommendation it could make would be sufficient to remedy the loss of SWWS as a comparator. Consequently, it recommended that both proposed mergers should be prohibited.

- Vivendi Water UK / First Aqua (2002): In 2002, a merger was proposed between Vivendi Water UK and First Aqua. To assist with their analysis of

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[22] *Lyonniase des Eaux SA and Northumbrian Water Group plc – a report on the merger situation,* Competition Commission, July 1995

[23] *Severn Trent plc and South West Water plc – a report on the proposed merger,* Competition Commission, October 1996; *Wessex Water plc and South West Water plc – a report on the proposed merger*, Competition

this proposed merger, the DGWS produced a model that attempted to quantify the value of the loss of a comparator[24]. Given the magnitude of the value of a comparator coming out of this analysis, the companies decided not to merge and instead agreed on a much smaller deal.

6.13 In Ofwat's recent analysis regarding the value of the loss of a comparator, it was assumed that this loss would impact at two levels:

- it affects the judgement of the efficiency frontier; and
- it reduces the number of data sets used in the statistical analysis.

6.14 The results generated by Ofwat's model are shown in Table A.4 below.

Table A.4: Ofwat model results – impact of losing a (very large local or medium regional company) comparator

Target Company	Turnover Range £m	Typical Company	Average Loss £m (NPV)	Range £m (NPV)
Very large local or medium regional company	76-150	Wessex, South East, South West, Southern	450	330-1330
Large regional company	151-300	Three Valleys, Dwr Cymru, Northumbrian, Anglian	540	420-1380
Huge regional company	301->401	North West, Severn Trent, Thames, Yorkshire	620	510-1440

6.15 As a result of this analysis, Ofwat concluded that the loss of value to customers of moving from 22 to 21 comparators, by losing a very large local or medium regional company could be between £330m and £1.4bn, depending on the size of the comparator that is lost. These figures include a cost to customers associated with the loss of a comparator in respect of capital expenditure as well operating expenditure. Clearly, on the basis of this analysis, the benefits from moving from a situation of a single independent entity to even a small number of comparators may be very significant indeed.

Commission, October 1996
[24] Vivendi Water UK plc and First aqua ltd, A report on the proposed merger, Competition Commission, November 2002.

Empirical evidence regarding economies of scale and scope

6.16 A number of studies have considered the extent to which there are economies of scale and economies of scope within comparable utility sectors.

6.17 Economies of scale are savings that are available to a single large business but not to multiple smaller businesses. For example, the fixed overheads associated with managing a gas distribution network will not vary significantly with the size of the business concerned, and, as such, a larger business will be able to spread these costs across a greater number of units and therefore achieve lower unit costs than a number of similar businesses operating on a smaller scale. However, above a certain size, businesses may experience diseconomies of scale i.e. increasing unit costs. This may be the result of communication and co-ordination problems across the over-large business.

6.18 Economies of scope are savings that arise where it is cheaper to produce two products together than it is to produce each separately. In the case of utilities, such savings may arise to the extent to which synergies can be achieved in the joint management of networks, for example in common areas such as logistics, overheads, asset management and workforce. Economies of scope in utilities will therefore be greatest where the geographical areas associated with different utility networks overlap.

6.19 The academic literature in relation to economies of scale is mixed:

- a report recently published by Ofwat [25] concluded that the water and sewerage companies display diseconomies of scale;
- findings of economies of scale in electricity distribution, have been subject to potential problems with respect to the data used and methodology applied[26];

[25] Stone and Webster (2004), "Investigation into Evidence for Economies of Scale in the Water and Sewerage Industry in England and Wales", January 2004.
[26] Monopolies and Mergers Commission (1997), " a report on a reference under article 15 of the Electricity (Northern Ireland) Order 1992", Appendix 8

- international evidence on scale economies in electricity distribution is mixed - where evidence of economies of scale has been found, this generally relates to:
    - very small electricity distribution networks[27]; or
    - increases in deliveries to existing customers rather than increases resulting from deliveries to new customers[28]; and
- international evidence on scale economies in gas distribution suggests that there are diseconomies of scale in relation to territorial expansion or expansions in the number of customers, and only economies of scale for expansions in output to a given number of customers[29].

6.20 On this basis, the evidence to support economies of scope within multi-utilities is stronger:

- a report recently published by Ofwat[30] concluded that there were some scope benefits between water and sewerage activities "where the ability to share inputs across activities is greatest"; and
- a study of Canadian multi-utilities[31] that combined activities such as water and sewerage and electricity distribution exhibited economies of scope, with costs 7 – 10% lower than non-multi-utility firms.

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[27] Yatchew (2000), "scale economies in electricity distribution: a semi-parametric analysis" Journal of Applied Econometrics, 15; Giles and Wyatt (1993), "Economies of scale in the New Zealand electricity distribution industry", Phillips, Models, Methods and Applications of Econometrics, Oxford: Blackwell; Salvanes and Tjotta (1998), "a test for natural monopoly with applications to Norwegian electricity distribution", Review of Industrial Organisation, 13.

[28] Roberts (1986), "Economics of density and size in the production and delivery of electric power", Land Economics, 62:4; Nelson and Primeaux (1988), "The effects of competition on transmission and distribution costs in the municipal electric industry", Land Economics, 64:4.

[29] Guldmann (1985) "Economies of scale and natural monopoly in urban utilities: the case of natural gas distribution", Geographical analysis, 17:4; and Rosellón and Halpern (2001), "Designing natural gas distribution concessions in a megacity: tradeoffs between scale economies and information disclosure in Mexico City", World Bank discussion paper.

[30] Stone and Webster (2004), "Investigation into Evidence for Economies of Scale in the Water and Sewerage Industry in England and Wales", January 2004.

[31] Yatchew (2000), "scale economies in electricity distribution: a semi-parametric analysis" Journal of Applied Econometrics, 15.

Ofgem assumptions regarding cost improvements for NGC and Transco

6.21 In establishing appropriate assumptions regarding the no sale option, it is appropriate to consider the rate of improvement in controllable costs currently assumed by Ofgem for regulated industries where comparators have not been available, namely for Transco and NGC:

- in September 2000, Ofgem published its final proposals on the price control for NGC's transmission asset owner business. In making these final proposals, Ofgem assumed that savings in controllable costs of around 3.5% per annum would be achieved; and

- in September 2001, Ofgem published its final proposals on Transco's price control for the period 2002 to 2007. These proposals assumed a forecast annual controllable operating expenditure reduction of 2.5%.

6.22 This evidence would suggest that in the event of no DN sales, Transco might continue to be expected to reduce its controllable operating expenditure by around 2.5% per annum. As such, in Ofgem's view, 3% represents a conservative assumption for the status quo rate of improvement in the absence of DN sales which:

- acknowledges that the equivalent percentage for NGC is 3.5% per annum; and

- reflects the fact that the introduction of separate DN price controls in 2003 may be expected to increase the rate of improvement in the absence of DN sales above historical trends by increasing the transparency of costs and allowing some limited comparisons to be made.

Appendix 7 Calculation of estimated potential benefits under an exogenous approach

Introduction

7.1 There are two alternative methodologies which could be applied to quantify the potential benefits of comparative regulation:

- Methodology 1 – an **exogenous** approach: which specifies the rate of change in DNs' allowed controllable operating expenditure going forward, in the event of DN sales and under the no sale option; and
- Methodology 2 – an **endogenous** approach: which specifies a range of input assumptions such as the starting level of inefficiency of each DN, the method of determining the efficiency frontier, the *actual* rate of improvement in operating expenditure and the rate of catch up to the frontier required of laggard DNs. These input assumptions are then applied to determine the rate of change in allowed operating expenditure going forward for each DN relative to the no sale option.

7.2 Under Methodology 1, the annual improvement in DNs' allowed operating expenditure, in the event of DN sales and under the no sale option, is an exogenous pre-determined variable. Under Methodology 2, the annual improvement in allowed operating expenditure is endogenous to the model and therefore calculated as a function of the other variables specified.

7.3 Ofgem has adopted a "Methodology 1" approach to maintain simplicity and transparency of the results presented. This approach is discussed in detail in this appendix. In Appendix 8, we discuss the application of "Methodology 2".

7.4 Ofgem would anticipate that in the event of DN sales:

- the allowed operating expenditure targets applicable to both IDNs and RDNs would reduce at a faster rate as a result of comparative regulation than they would otherwise have done under the no sale option;

- this targeted rate of improvement is expected to, on average, be the same across all DNs and not differentiate between IDNs and RDNs despite potential differences in actual underlying performance absent the appropriate incentives; and

- the targeted rate of DN improvement, in the event of DN sales, is expected to vary in accordance with the number of additional comparators generated by DN sales. For example, the creation of four additional comparators would generate a greater rate of improvement than the creation of three or fewer additional comparators, and so on.

7.5 As such, Ofgem has developed a methodology that reflects this rationale through the simple specification of a DN sales case, and a "no sale" option, where the no sale option provides a reference case for the benefits assessment. This benefits assessment simply compares the reduction in allowed operating expenditure (and hence the impact on customer charges) achieved under the DN sales option with that assumed under the no sale option. In both cases, the reduction in allowed operating costs is derived by applying an assumed rate of reduction (henceforth referred to as an assumed rate of improvement) to a quantification of DN allowed operating costs. The regulatory outcome for the current price control period is assumed to be fixed, and as such benefits are only assumed to accrue from 2008 onwards[32]. In the sub-sections that follow, we consider:

- the assumed rates of improvement in allowed operating costs;

- the estimation of DN operating costs;

- the present value (PV) methodology applied; and

- the results obtained.

[32] As Ofgem is not proposing to re-open the current price control, which is scheduled to run until 31 March 2008, it is assumed that no benefits will be passed to consumers prior to this date.

Assumed rates of improvement

7.6 Ofgem has developed assumptions for the following key model inputs:

- **No sale option average rate of improvement in allowed controllable operating costs:** the rate of improvement in allowed controllable operating expenditure that would be set by Ofgem for all DNs in the absence of DN sales; and

- **DN sales average rate of improvement in allowed controllable operating costs:** the rate of improvement in allowed controllable operating expenditure that would be set by Ofgem for all DNs in the event of DN sales.

7.7 These rates are assumed to vary:

- in accordance with the number of additional comparators assumed; and

- over time.

7.8 Each of these drivers is considered in turn below.

Impact of number of additional comparators

7.9 As stated above, it is assumed that the greater the number of additional comparators generated by the DN sales process, the greater the rate of improvement in allowed operating expenditure and hence the greater the benefits to customers.

7.10 As such, the assumed rate of improvement in allowed controllable operating costs varies with respect to the number of comparators assumed in addition to Transco's RDN business. Four different scenarios have been considered in this respect, relating to the generation of between one and four additional comparators. The rates of improvement associated with the creation of four additional comparators, and the no sale option i.e. no additional comparators, have been determined exogenously using historical data to inform their determination. However, the improvement rates assumed for the cases that consider the possibility of between one and three additional comparators have been established on the basis that:

- they lie within the range specified for between one and four additional comparators; and

- there will be diminishing returns to each additional comparator, specifically, that each additional comparator is 30% less valuable than the previous one.

7.11 The assumptions applied are shown in Table A.5 below. The two key percentages applied in the no sale and sale options under the base case, on the assumption of three additional comparators are highlighted in bold.

Table A.5: Assumptions applied under Methodology 1

		High case	Base case	Low case
No sale option average rate of improvement		3%	**3%**	3.25%
DN sales average rate of improvement in allowed controllable operating expenditure	4 additional comparators	5.8%	4.3%	4%
	3 additional comparators	5.40%	**4.13%**	3.91%
	2 additional comparators	4.86%	3.87%	3.77%
	1 additional comparator	4.09%	3.5%	3.55%

Profiling of rates of improvement

7.12 Ofgem has also considered the profile of improvement that may be achieved by DNs in the event of DN sales and their impact on any present values (PVs) derived. The benefits that are potentially achievable over the next three full regulatory periods have been assessed covering the period 2008/9 – 2022/23. Two alternative profiles have been considered for these three regulatory periods:

- constant rate of improvement: application of a constant rate of improvement throughout the period; and
- bell shaped improvement, with:
  - relatively low rates of improvement in the first full regulatory period; then
  - the greatest rate of improvement in the second full regulatory period, as Ofgem obtains more information regarding each DN's relative efficiency; and

- the lowest rate of improvement in the third full regulatory period, to reflect the assumption that the largest efficiency gains driven by DN sales would have been exploited already.

7.13 Ofgem has received representations from industry participants in response to previous studies that to use a flat rate throughout the period of evaluation may not be realistic. These respondents argue that it is unlikely that, because of the relatively short duration between the transaction and the end of the current price control period, many of the benefits of comparative regulation will be passed through to customers within the first full regulatory period i.e. that a bell shaped rate of improvement over the three regulatory periods of evaluation is most appropriate. Having regard to these representations, a bell shaped profile has been adopted by Ofgem for presentation of its core results in Chapter 8. In this Appendix, results are presented from the application of both a flat profile, and a bell-shaped profile. In both cases, the profiles considered are consistent with the assumed average rates of improvement for DNs i.e. the compound annual growth rate (CAGR) over the three full regulatory periods modelled is held constant between bell-shaped and flat rate profiles.

7.14 As a result, under the flat profile, the rates of improvement over the period 2008/9 – 2022/23 are assumed to be constant, at the rates specified in Table A.5 above in each year of the period.

7.15 The assumed rates of improvement in allowed controllable operating expenditure over the three regulatory periods considered for the bell-shaped profile are shown in Table A.6, Table A.7, and Table A.8 below. In each case, the rate applied *within* each regulatory period is assumed to be the same.

Table A.6: Assumptions applied under Methodology 1 – high case, bell profile

		Period 1: 2008/9 to 2012/13	Period 2: 20013/14 to 2017/18	Period 3: 2018/19 to 2022/23	Average
DN sales average rate of improvement in allowed controllable operating expenditure	4 additional comparators	5.00%	9.00%	3.25%	5.8%
	3 additional comparators	4.73%	8.19%	3.22%	5.40%
	2 additional comparators	4.34%	7.03%	3.17%	4.86%
	1 additional comparator	3.79%	5.37%	3.10%	4.09%

Table A.7: Assumptions applied under Methodology 1 – base case, bell profile

		Period 1: 2008/9 to 2012/13	Period 2: 20013/14 to 2017/18	Period 3: 2018/19 to 2022/23	Average
DN sales average rate of improvement in allowed controllable operating expenditure	4 additional comparators	4.30%	5.50%	3.10%	4.3%
	3 additional comparators	4.12%	5.16%	3.09%	4.13%
	2 additional comparators	3.87%	4.68%	3.07%	3.87%
	1 additional comparator	3.51%	3.99%	3.04%	3.5%

Table A.8: Assumptions applied under Methodology 1 – low case, bell profile

		Period 1: 2008/9 to 2012/13	Period 2: 20013/14 to 2017/18	Period 3: 2018/19 to 2022/23	Average
DN sales average rate of improvement in allowed controllable operating expenditure	4 additional comparators	4.00%	4.75%	3.30%	4%
	3 additional comparators	3.90%	4.55%	3.29%	3.91%
	2 additional comparators	3.75%	4.26%	3.28%	3.77%
	1 additional comparator	3.55%	3.84%	3.27%	3.55%

The estimation of DN operating costs

7.16 In each case, controllable operating costs have been defined to be consistent with the levels allowed upon separation of Transco's distribution price control[33] i.e. allowed operating expenditure net of network rates, which are a key controllable cost faced by GTs.

7.17 In manipulating these controllable costs, as specified upon separation of the price controls, the following adjustments have been made:

♦ upon separation of Transco's distribution price control, allowed operating expenditure net of network rates was specified for the period 2002/3 to 2006/7. Following the extension of the current distribution price control period by one year, it has therefore been necessary to extrapolate 2006/7 values to derive a value for 2007/8. In performing this extrapolation, it has been assumed that 2007/8 allowed controllable operating expenditure net of network rates will be 3% lower than in 2006/7[34];

[33] Separation of Transco's distribution price control, Final proposals, June 2003, Table 2.3.
[34] Note that this assumptions should not fetter in any way, the Authority's decision regarding the allowed operating expenditure for DNs in 2007/8.

- the costs specified upon separation of Transco's distribution price control were in 2000 prices, it has therefore been necessary to inflate these to 2004 prices[35]; and

- a further adjustment has been made to net off the costs associated with the Agency which would be implemented given the Authority's conclusions on Agency and Governance in May 2004.

7.18 Although the first two adjustments are relatively straight-forward, the third point warrants further explanation. As discussed in Chapter 5, an Agency is proposed to mitigate some of the costs that would otherwise be incurred in the event of DN sales. However, creation of such an Agency in the event of DN sales will mean that a proportion of each DN's cost base will relate to the central provision of services by the Agency. As a result, when quantifying the benefits of DN sales as a result of comparative regulation, these non-comparable costs have been netted off the estimates of controllable DN operating expenditure used.

7.19 An indicative estimate of the DN related Agency costs, given Ofgem proposals, has been provided by NGT and netted off the assumed controllable costs for the eight DN businesses. NGT has estimated that annual Agency costs associated with Option C, as proposed, would be £39,093k in total, £32,812k of which would be attributed to the distribution cost base, with the remainder attributed to the NTS. As a result, £32,812k has been deducted from the estimate of 2007/8 allowed controllable operating expenditure.

7.20 The value of allowed controllable operating expenditure in 2007/8 has then been used as the starting point for the analysis of benefits. The assumed improvement rate for DNs in 2008/9 was applied to the controllable operating expenditure in 2007/8 to provide an estimation of allowed controllable operating expenditure for 2008/9. Following this, the annual improvement rate for 2009/10 was applied to the estimate of allowed controllable operating expenditure in 2008/9 and so on.

7.21 The difference between the allowed controllable operating expenditure estimated for the no sale option and that derived under DN sales then generates the annual stream of customer benefits.

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[35] Inflation factor of 1.097 has been applied – based on Office for National Statistics RPI data

The net present valuation methodology applied

7.22 With respect to the timing of the DN sales process, should it proceed, the following assumptions have been made:

- as Ofgem is not proposing to re-open the current price control, it is assumed that no benefits will be passed to consumers within the current price control period;
- the next price control period will commence on 1 April 2008, with each subsequent regulatory period lasting for five years; and
- if DN sales proceed to the current commercial timetable, GT licences will be transferred from Transco plc to wholly owned Transco subsidiary companies at the end of April 2005. At this point, the HSE will be able to review the DNs' safety cases. Once these approvals have been obtained, NGT will be able to proceed towards completing the proposed sales. DN sales may therefore take effect from the end of May 2005 onwards. The modelling works on a financial year basis, and as such, has assumed that DN sales will take effect from 1 April 2005. Though this does not fully reflect the current commercial timetable, the impact on the cost benefits calculation is negligible, and represents a conservative approach as costs are assumed to be incurred sooner whilst in either case, the benefits are not realised until 1 April 2008.

7.23 In calculating present values (PVs), benefits are therefore assumed to occur during the period 2008/9 – 2022/23, and these benefits have been discounted back to 2004 using a discount rate of 6.25%, which is the cost of capital assumed within Transco's current price control review.

Results using Methodology 1

7.24 Table A.9 and Table A.10 below present the results of our analysis, applying "Methodology 1". In Table A.9, the results associated with application of a bell-shaped profile, as discussed above are presented. These results are consistent with those presented in Chapter 8. In Table A.10, the results associated with application of a flat profile, i.e. a constant rate of DN improvement across all years in the period 2008/9 – 2022/23, are presented.

Table A.9: Benefits outcome for different sales scenarios – "bell-shaped" profiles

Number of additional comparators	High case PV (£m, 2004 prices)	Base case PV (£m, 2004 prices)	Low case PV (£m, 2004 prices)
1	275	145	84
2	450	242	142
3	565	308	181
4	642	353	208

Table A.10: Benefits outcome for different sales scenarios – "flat" profiles

Number of additional comparators	High case PV (£m, 2004 prices)	Base case PV (£m, 2004 prices)	Low case PV (£m, 2004 prices)
1	257	122	70
2	423	205	117
3	534	261	150
4	608	300	173

7.25 It is noted that, given the profiling adopted within the bell-shaped profiles applied, the benefits are slightly higher under the bell-shaped profiles than under the flat profiles.

7.26 Given the estimates of consequential benefits of £17.4m stated in Chapter 8, and the high, base and low case cost estimates presented in Table 8.2. The net benefits, for the Methodology 1, bell-profile approach for all potential additional comparators, in the high, low and base case scenarios are presented in Table A.11 below.

Table A.11: PFP operating expenditure derived for GB utilities

Number of additional comparators	High case PV (£m, 2004 prices)	Base case PV (£m, 2004 prices)	Low case PV (£m, 2004 prices)
1	210	60	-16
2	385	157	41
3	500	223	81
4	578	268	108

Appendix 8 Calculation of estimated potential benefits under an endogenous approach

Introduction

8.1 There are two alternative methodologies which could be applied to quantify the potential benefits of comparative regulation:

- Methodology 1 - an **exogenous** approach: which simply specifies the rate of change in DNs' allowed controllable operating expenditure going forward, in the event of DN sales and under the no sale option; and

- Methodology 2 - an **endogenous** approach: which specifies a range of input assumptions such as the starting level of inefficiency of each DN, the method of determining the efficiency frontier, the *actual* rate of improvement in operating expenditure and the rate of catch up to the frontier required of laggard DNs. These input assumptions are then applied to determine the rate of change in allowed operating expenditure going forward for each DN relative to the no sale option.

8.2 Therefore under Methodology 1, the annual improvement in DNs' allowed operating expenditure, in the event of DN sales and under the no sale option, is an exogenous pre-determined variable. Under Methodology 2, the annual improvement in allowed operating expenditure is endogenous to the model and therefore calculated as a function of the other variables specified.

8.3 The results stated in Chapter 8 (and described in further detail in Appendix 2) are based on the application of Methodology 1, which is Ofgem's preferred methodology. However, since NGT notified the industry of its wish to sell one or more of its regional distribution networks in May 2003, a number of organisations have conducted studies on the likely level of consumer benefit that could arise from this proposed sale[36]. Specific detail of the modelling methodologies used no doubt differ between organisations, however, some of these studies lack clarity with respect to:

- which of the methodologies described above has been applied;
- the importance of the assumptions specified, and the sensitivity of results to their variation; and
- the specification of the counterfactual applied.

8.4 However, in each case, the use of assumptions in addition to the simple Methodology 1 approach implies approaches more akin to Methodology 2. The assumptions made by these studies for the scenario associated with the sale of four DNs are detailed in Table A.12 below.

Table A.12: Summary of key assumptions made by other studies (sale of 4 DNs)

Assumption	**Study**		
	ILEX	**NGT**	**BGT/OXERA**
DN starting inefficiency	0-30%	0-30%	0-30%
Catch-up rate	50% in first period. 66% thereafter.	75%	50%
Catch-up duration	5 years	5 years	5 years
Frontier	1st company	1st company	2nd company
Frontier shift	0%	0%	0%
IDN efficiency gain	4.3%	4.3%	4%
RDN efficiency gain	4%	4%	3%
Efficiency gain if none sold	3%	3%	3%
Merger savings	None	9% to 13% combination synergies in first 3 years	None
Economies of scale lost	None	None	*5% operating expenditure modelled as a sensitivity to the base case*

8.5 In order to achieve simplicity and transparency in presenting the results of its review of the benefits analysis for the purpose of this Final IA, Ofgem has:

[36] The studies performed by OXERA, NGT and ILEX are discussed in Chapter 8.

- focused on the application of Methodology 1 and the use of historical trends in allowed operating expenditure to inform the assumption applied; and
- clearly specified a counterfactual.

8.6 Whilst Ofgem believes that Methodology 1 represents the clearest, simplest and most robust approach, Ofgem has also considered the application of Methodology 2, to ensure that it is consistent with the results obtained under Methodology 1.

8.7 This Appendix summarises Methodology 2 by:

- providing an overview of the methodology applied;
- describing the implications of the methodology applied for benefits estimation; and
- presenting the results of model simulations to demonstrate the extent to which the model generates results that are consistent with those established under Methodology 1.

Description of methodology

8.8 This section discusses the alternative Methodology 2 approach and the way in which it was implemented.

8.9 Where the Methodology 1 approach adopted in Chapter 8 and Appendix 7 addressed only the overall reductions in allowed operating expenditure, this alternative approach considers other factors and how they feed into reductions in both actual and allowed operating expenditure for each network. As such, the overall reduction in allowed operating expenditure is not an external input to the model.

8.10 In particular, the Methodology 2 approach considers the following inputs in addition to the Methodology 1 approach for the DN sales option:

- reductions in actual operating expenditure in the case where network sales occur, both for newly independent distribution networks (IDNs) and for distribution networks retained by Transco (RDNs);
- the rate of initial inefficiency inherent in each network at the time of sales;

- the ownership of each network;

- catch up proportions – the proportion of the efficiency gap between a network and the frontier that must be eliminated during the next price control period;

- catch up rates – the number of years that a network has to catch up by the given amount; and

- frontier shift rate – the underlying rate at which networks are expected to improve in addition to catch up.

8.11 The no sale option is the same under both Methodology 1 and Methodology 2. This is described in greater detail in Appendix 3. To summarise, under this option, allowed controllable operating costs for all DNs are assumed to reduce at a rate of 3% per annum. The use of the same no sale option ensures consistency across approaches, furthermore, in Ofgem's view it is not appropriate to apply catch-up rates or frontier shift rates under the no sale option as it assumed that full comparative regulation will not be possible absent the existence of independent comparators.

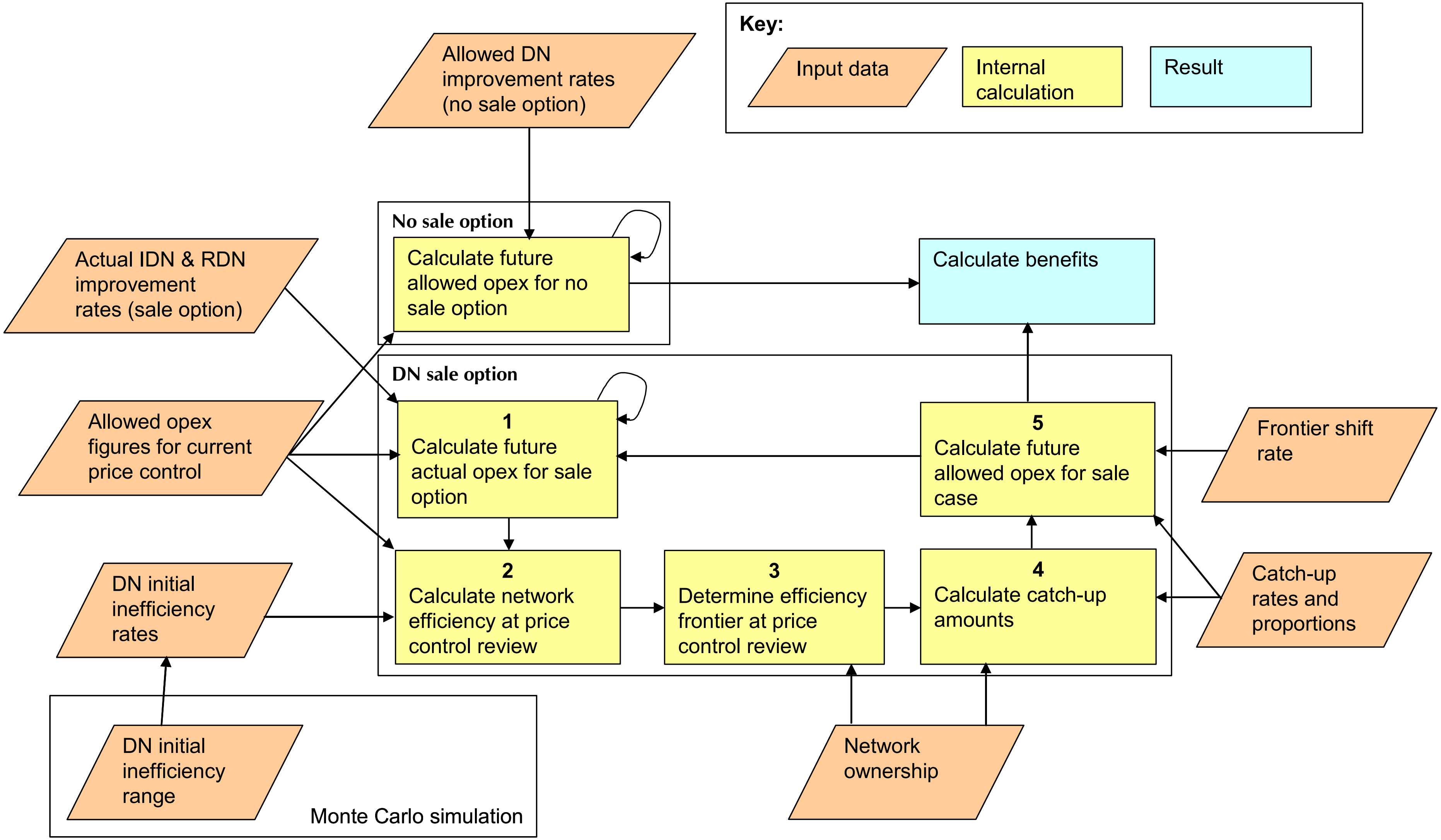
8.12 Methodology 1 and Methodology 2 therefore have the following inputs in common:

- reductions in allowed controllable DN operating expenditure assumed under the no sale option; and

- allowed controllable operating expenditure for each DN during the current price control period i.e. in the period to 31 March 2008.

8.13 The general structure of the model is shown in Figure A.6 below.

Figure A.6


Key:
Input data
Internal calculation
Result
Allowed DN improvement rates (no sale option)
No sale option
Calculate future allowed opex for no sale option
Calculate benefits
Actual IDN & RDN improvement rates (sale option)
DN sale option
Allowed opex figures for current price control
1
Calculate future actual opex for sale option
5
Calculate future allowed opex for sale case
Frontier shift rate
2
Calculate network efficiency at price control review
3
Determine efficiency frontier at price control review
4
Calculate catch-up amounts
Catch-up rates and proportions
DN initial inefficiency rates
DN initial inefficiency range
Monte Carlo simulation
Network ownership

8.14 Given that the no sale options applied in both approaches are the same, the remainder of this section therefore focuses on the DN sales case and the methodology applied under a Methodology 2 approach.

8.15 As in Methodology 1, the regulatory outcome for the current price control period is assumed to be fixed and, as such, benefits are only assumed to accrue from 2008 onwards[37]. However, under the DN sales option, the operating expenditure actually incurred during the current price control period is assumed to decline from the allowed operating expenditure level assumed for 2005/6 at a specified rate (as specified in the input assumptions). Whilst this does not generate a flow of benefits during the period to 31 March 2008, it is assumed that the level of actual controllable operating expenditure incurred in 2007/8 will be used to inform Ofgem's view of the efficiency of each network, and hence the appropriate level of allowed operating expenditure for the period 2008/9 to 2012/13[38].

8.16 The factors that are assumed to inform the determination of allowed operating expenditure in the first full regulatory period following DN sales, include:

- ♦ the assumed starting inefficiency of each network;
- ♦ the rate of improvement assumed to be achieved by each network (distinguishing between RDNs and IDNs) during the current price control period (i.e. period to 31 March 2008); and
- ♦ network ownership, whereby networks under common ownership are assumed to achieve the same rate of efficiency as each other i.e. it is assumed that only the average efficiency for the group will be transparent to Ofgem rather than the efficiency of each individual network within the group.

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[37] As Ofgem is not proposing to re-open the current price control, which is scheduled to run until 31 March 2008, it is assumed that no benefits will be passed to consumers prior to this date.

[38] It is noted that this assumption is an over-simplification of reality. Ofgem will only have actual data for 2006/7 at the time of the next price control review and will need to form an estimate of actual costs for 2007/8 based on company forecasts and efficiency assumptions.

8.17 We have focused our analysis on the current "sales option". This sales option is based on the announcement by NGT in August of this year that it had reached agreement on the sale of four of its gas distribution networks to three independent parties, as follows:

- ♦ The North of England distribution network is to be sold to a consortium led by Cheung Kong Infrastructure Holdings Limited and including United Utilities PLC;
- ♦ The Wales & West distribution network is to be sold to a consortium led by the Macquarie European Infrastructure Fund; and
- ♦ The South of England and Scotland distribution networks are to be sold to a consortium comprising Scottish and Southern Energy plc, Borealis Infrastructure management Inc and Ontario Teachers Pension Plan.

8.18 As such, the four networks which will be sold, should DN sales proceed, are assumed to be those listed above. Furthermore, it is assumed that the four remaining DNs, which are not being sold, remain under the common ownership of NGT, and that the two networks that are being bought by the consortium comprising Scottish and Southern Energy plc and others will also share a common owner.

8.19 At the first price control review following DN sales, should it proceed, the efficiencies of the networks are assumed to be compared, and the efficiency frontier is set at that point. The obscuring of actual inefficiencies in networks under common ownership has a retarding effect on the frontier, as networks in common ownership are less likely to be identified as more efficient than other networks (though, equally, are less likely to be substantially behind the average).

8.20 Once the efficiency frontier is determined, the efficiency of each network relative to the frontier is calculated. Allowed controllable operating costs are then determined such that the less efficient companies must "catch up" with the efficiency frontier over a number of years. Two input variables are therefore specified:

- the catch up proportion i.e. the proportion of the assessed gap between the company and the efficiency frontier that the company is required to catch-up; and

- the catch-up rate i.e. the number of years each company is given to catch-up the required amount.

8.21 Such catch-up parameters tend to be specified either to reflect the fact that a lead time may be required for a less efficient company to achieve significant performance improvements or to reflect some uncertainty with respect to determination of the frontier. Therefore catch-up rates may be influenced by the number of comparators, as a greater number of comparators may give the regulator greater confidence in the specification of the frontier.

8.22 The required catch up improvement in each year is then combined with the assumed rate of frontier shift to set the allowed operating expenditure for each network over the subsequent five-year period.

8.23 In each of the three full regulatory periods, actual operating expenditure assumed to be incurred by each network is established by applying the assumed actual improvement rate[39], unless the catch up amounts imposed require a greater rate of improvement. In the case where the imposed catch up requires a greater rate of improvement, the actual operating expenditure is assumed to decrease at the same rate as allowed operating expenditure[40].

[39] The most efficient network improves at a different rate, input separately from the underlying improvement rates of other DNs. This is to reflect the possibility that the scope for efficiency improvements is lower at the frontier, or just that having been identified as the most efficient network, the company puts less emphasis on identifying and implementing efficiency savings opportunities.

[40] By assuming that the specified catch-up amounts may drive a rate of improvement higher than the assumed actual improvement rate, we are acknowledging that there will be a relationship between the targeted rate of improvement and those that are actually achieved.

8.24 Monte Carlo analysis involves setting a number of input variables by randomly sampling from a given distribution, noting the benefits figure, and repeating several thousand times. The distribution of results gives a benefits estimate that takes account of the uncertainty in those variables. Monte Carlo simulation has been applied to the initial inefficiency in each network. This variable allows the relative efficiency of each company to be identified, and the efficiency frontier to be calculated at the first price control review.

8.25 As in Methodology 1, customer benefits are assumed to be driven by reductions in allowed operating expenditure of the DNs. Therefore, the difference between the allowed controllable operating expenditure estimated for the no sale option and that derived under DN sales then generates the annual stream of customer benefits. Where the actual operating expenditure is less than the allowed operating expenditure, additional benefits are gained by network owners and shareholders – these are societal benefits, but as they do not accrue to consumers, they are not included in the consumer benefits figures reported here.

8.26 With respect to the timing of the DN sales process, should it proceed, the following assumptions have been made:

- as Ofgem is not proposing to re-open the current price control, it is assumed that no benefits will be passed to consumers within the current price control period;
- the next price control period will commence on 1 April 2008, with each subsequent regulatory period lasting for five years; and
- if DN sales proceed to the current commercial timetable, GT licences will be transferred from Transco to wholly owned Transco subsidiary companies at the end of April 2005. At this point, the HSE will then be able to review the DNs' safety cases. Once these approvals have been obtained, NGT will be able to proceed towards completing the proposed sales. DN sales may therefore take effect from the end of May 2005 onwards. The modelling works on a financial year basis, and as such, has assumed that DN sales will take effect from 1 April 2005. Though

this does not fully reflect the current commercial timetable, the impact on the cost benefits calculation is negligible, and represents a conservative approach as costs are assumed to be incurred sooner whilst in either case, the benefits are not realised until 1 April 2008.

8.27 In calculating PVs, benefits are therefore assumed to occur during the period 2008/9 – 2022/23, and these benefits have been discounted back to 2004 using a discount rate of 6.25%.

Implications for benefits estimation

8.28 This section discusses the use of the alternative model to inform the benefits figures calculated in Chapter 8.

8.29 As discussed in the previous section, the methodology applied makes a number of assumptions with respect to the starting inefficiency of firms, the rate of catch-up required of those firms, and the rate of frontier shift applied. However, there are areas of the methodology and assumptions applied that potentially differ from similar studies previously conducted. These relate to:

- ownership assumptions;
- differential treatment of IDNs, RDNs, and the frontier DN;
- frontier shift;
- initial inefficiency assumptions; and
- the counterfactual.

8.30 Each of these areas is discussed in turn below.

Ownership assumptions

8.31 In a post DN sales environment, those DNs that share a common owner are treated as a single entity for determination of the efficiency frontier. Given that only three truly independent comparators are created, the efficiency frontier determined is less demanding than would otherwise have been the case, and the benefits to customers are accordingly lower.

Differential treatment of IDNs, RDNs, and the frontier DN

8.32 The methodology applied assumes three different rates of actual operating expenditure improvement, applicable to IDNs, RDNs, and whichever DN (or group of DNs) is deemed to be at the efficiency frontier. In the cases presented below, it has been assumed that:

- IDNs improve their actual controllable operating costs at a faster rate than RDNs. This reflects the fact that the new management and greater possibility of economies of scope within IDNs may allow them to achieve a faster rate of efficiency improvement; and

- the rate of improvement of the DN, deemed to be at the efficiency frontier, is separately specified. In the majority of cases presented below, this rate is assumed to be less than that assumed for either the IDNs or RDNs. This reflects the fact that companies at the frontier may have exhausted a large number of efficiency opportunities and also may face reduced incentives for further improvements. The application of a lower rate of improvement to the frontier DN means that the efficiency frontier determined is less demanding than would have been the case had a single rate of improvement been applied across IDNs or RDNs, and the benefits to customers are accordingly lower.

8.33 At this stage, it is worth re-emphasising the distinction between the percentage improvements assumed with respect to *actual* operating expenditure under Methodology 2, which is the subject of this appendix, and the percentage improvements in *allowed* operating expenditure under Methodology 1. Allowed levels of operating expenditure are assumed to drive benefits to customers. Under Methodology 2, the level of allowed operating expenditure is the output of the range of assumptions including initial inefficiency, actual operating expenditure reductions and catch-up. In general, regulated companies achieve actual improvements in efficiency over and above their efficiency targets, at a benefit to their shareholders. As such, the rate of improvement of *actual* operating expenditure applied within Methodology 2 is, in general, assumed to be higher than the rate of improvement assumed with respect to *allowed* operating expenditure under Methodology 1.

Frontier shift

8.34 As earlier in this appendix shows, the three studies performed by ILEX, NGT and OXERA assumed that the efficiency frontier would not shift within a given price control period.

8.35 In Ofgem's view, this would imply either that the most efficient companies will not have an underlying rate of improvement during a given price control period or that any such improvements will be passed in full to shareholders during the same period. In Ofgem's view an assumption of zero frontier shift is therefore overly conservative, and inconsistent with current Ofgem policy on this matter. As such, in the cases presented below, Ofgem has applied a rate of frontier shift to reflect the continuing productivity improvement of all companies within the gas sector.

Initial inefficiency assumptions

8.36 In the majority of the cases presented below, the initial inefficiencies of each DN at the time of DN sales, are assumed to be sampled from a range between 0% and 30%. However, evidence from other sectors suggests that this may be conservative, and as such, in a number of cases a range of 0% to 40% has been assumed. The evidence from other sectors is as follows:

- evidence from Ofwat suggests that the range of observed inefficiency was 47% in 1993/4[41], 40% in 2001/2[42], and was more than 30% in 2002/3[43]; similarly

[41] Ofwat, 1993-94 report on the costs of water delivered and sewage collected, Table 7 using combined water services model, 1994.

- at the third distribution price control review, Ofgem presented analysis that suggested a range of circa 40%[44].

Counterfactual

8.37 As stated earlier, the counterfactual, or no sale option, is assumed to be the same across both Methodology 1 and Methodology 2. As such, it is assumed that, in the absence of DN sales, *allowed* operating costs will reduce at a rate of 3% in the base and high case, and a rate of 3.25% in the low case. As emphasised above, this cannot be compared to the rates of improvement in *actual* operating expenditure assumed for the DN sales case under Methodology 2. In fact an *actual* rate of improvement of 3% would generate a much lower rate of improvement in *allowed* operating costs for the no sale option and hence increase the differential between the sale and no sale option and hence increase the perceived benefits of DN sales. However in Ofgem's view, such an approach would not be appropriate.

Results using Methodology 2

8.38 In this section, we present a series of "assumption combinations" that broadly achieve the same benefits as the Methodology 1 analysis.

8.39 In the Methodology 1 base case, customer benefits were assessed as having an PV of circa £310m. Table A.13 below shows the assumption combinations under a Methodology 2 approach that achieve similar results.

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[42] Ofwat, 2000-2001 Report on water and sewerage unit costs and relative efficiency, December, page 18, 2002.
[43] Ofwat, Water and sewerage service unit costs and relative efficiency 2002-2003 report, page 4.
[44] Ofgem, Reviews of Public Electricity Suppliers 1998 to 2000: Distribution Price Control Review: Final Proposals, December, Table 2.8, 1999.

Table A.13: Methodology 2 assumptions that replicate the Methodology 1 base case

Number of sold networks:	4	4	4
Network ownership:	As announced		
Efficiency frontier:	Most efficient network (after ownership effects are taken into account)		
DN initial inefficiency[45]:	0% to 30%	0% to 30%	0% to 40%
Catch up proportion for three additional comparators:	62.5%	62.5%	80%
Number of years to catch up:	5	5	5
Frontier shift rate:	2%	1.5%	1.5%
Most efficient company actual improvement rate[46]:	3.0%	3.0%	4.3%
RDN actual improvement rate[47]:	4.44%	4.61%	3.98%
IDN actual improvement rate[48]:	4.95%	5.20%	4.30%
Benefits PV (£m)	£307m to £313m		

8.40 In the Methodology 1 low case, customer benefits were assessed as having an PV of circa £180m. Table A.14 below shows the assumption combinations under a Methodology 2 approach that achieve similar results.

[45] Uniformly randomly distributed between the parameters specified. Represents the percentage of the sale year allowed controllable operating expenditure.
[46] Only applies after the first price control review
[47] Does not apply to the frontier company from 2008 onwards.
[48] See footnote above.

Table A.14: Methodology 2 assumptions that replicate the Methodology 1 low case

Number of sold networks:	4	4	4
Network ownership:	As announced		
Efficiency frontier:	Most efficient network (after ownership effects are taken into account)		
DN initial inefficiency[49]:	0% to 30%	0% to 30%	0% to 40%
Catch up proportion for three additional comparators:	62.5%	62.5%	80%
Number of years to catch up:	5	5	5
Frontier shift rate:	2%	1.5%	1.5%
Most efficient company actual improvement rate[50]:	3.00%	3.00%	3.95%
RDN actual improvement rate[51]:	4.12%	4.33%	3.74%
IDN actual improvement rate[52]:	4.50%	4.80%	3.95%
Benefits PV (£m)	£181m to £182m		

8.41 In the Methodology 1 high case, customer benefits were assessed as having an PV of circa £565m. Table A.15 below shows the assumption combinations under a Methodology 2 approach that achieve similar results.

[49] Uniformly randomly distributed between the parameters specified. Represents the percentage of the sale year allowed controllable operating expenditure.
[50] Only applies after the first price control review
[51] Does not apply to the frontier company from 2008 onwards.
[52] See footnote above.

Table A.15: Methodology 2 assumptions that replicate the Methodology 1 high case

Number of sold networks:	4	4	4
Network ownership:	As announced		
Efficiency frontier:	Most efficient network (after ownership effects are taken into account)		
DN initial inefficiency[53]:	0% to 30%	0% to 30%	0% to 40%
Catch up proportion for three additional comparators:	62.5%	62.5%	80%
Number of years to catch up:	5	5	5
Frontier shift rate:	2%	1.5%	1.5%
Most efficient company actual improvement rate[54]:	3%	3%	5.5%
RDN actual improvement rate[55]:	5.48%	5.66%	5.03%
IDN actual improvement rate[56]:	6.45%	6.70%	5.80%
Benefits PV (£m)	£567m to £570m		

8.42 In Ofgem's view, the analysis presented above confirms the validity of the Methodology 1 approach adopted, and its associated assumptions. In Ofgem's view, Methodology 1 represents a more transparent and robust way of presenting benefits analysis than a Methodology 2 approach, which is overly complex and where the extent to which different assumptions drive results is unclear.

[53] Uniformly randomly distributed between the parameters specified. Represents the percentage of the sale year allowed controllable operating expenditure.
[54] Only applies after the first price control review
[55] Does not apply to the frontier company from 2008 onwards.
[56] See footnote above.

Appendix 9 Calculation of estimated potential consequential benefits associated with the sale option

9.1 In Chapter 8 we provided a high-level overview of the potential benefits associated with the proposed framework of arrangements that would be put in place in the event of DN sales. In this Appendix we provide further detail for each of the areas covered by the four RIAs issued on the nature of the proposed arrangements.

Roles and responsibilities

9.2 As discussed in Chapter 5, in the Roles and Responsibilities conclusions document, the Authority opted for Option 1, proposing an active role for each DN owner consistent with the current allocation of roles and responsibilities within Transco.

9.3 Whilst a cost benefit analysis of the different options under consideration was performed within the Roles and Responsibilities RIA document, this assessed Option 2 and Option 3 relative to Option 1. This analysis concluded that both Option 2 and Option 3 would imply a ***loss*** of potential benefit relative to Option 1 as a result of:

- contractual complexity;
- regulatory costs; and
- a weakening of comparative regulation.

9.4 For the purposes of the Final IA, it is necessary to consider the likely costs and benefits of the proposed framework (i.e. Option 1) relative to the status quo i.e. the no sale option.

9.5 As the option chosen is consistent with the current allocation of roles and responsibilities within NGT, there are not assumed to be any benefits relative to the status quo. Rather, the option chosen serves to mitigate the loss of benefits (including those relating to comparative efficiency) that would otherwise potentially occur were alternative allocations of roles and responsibilities chosen.

9.6 As a result, we do not assume any consequential benefits associated with the roles and responsibilities proposals within the Final IA. Ofgem's analysis of the comparative efficiency benefits that would result from DN sales was presented in the preceding section, and in Ofgem's view does not need to be amended in the light of these roles and responsibilities proposals.

9.7 The costs associated with the proposed framework are considered in the following section.

Agency and governance

9.8 Under the status quo, shippers face a single interface with NGT and roles and responsibilities are assigned through NGT's internal organisational structure. However, in the event of DN sales, certain activities will be the responsibility of a number of separate DN entities. As a result, costs incurred are likely to be higher than the status quo as the number of interfaces faced by shippers will increase, and there will be a risk of duplication.

9.9 As a result, Ofgem considers that the DN sales process could not proceed without the creation of a central service provider (Agency) which could discharge many of the functions and services that are currently provided by Transco and hence mitigate many of the costs that would otherwise be incurred.

9.10 In the Agency and Governance RIA, Ofgem performed a qualitative cost benefit assessment of different Agency options relative to a situation in which DN sales are assumed to proceed but no Agency is created. In the Agency and Governance conclusions document, Option C was chosen to ensure an appropriate balance between accountability and cost mitigation.

9.11 However, for the purposes of the Final IA, it is necessary to consider the likely costs and benefits of the proposed framework relative to the status quo. As the Agency proposals are being proposed to mitigate the increase in costs relative to the status quo, we do not assume any benefits associated with these proposals within the Final IA. Rather, the impact of the Agency arrangements proposed is seen in the assessment of the costs of the proposed framework. These costs which are considered in Chapter 9 are significantly lower than would otherwise be the case were no Agency arrangements proposed.

Offtake arrangements

NTS exit capacity

9.12 As discussed in Chapter 5, in the Offtake arrangements conclusions document, the Authority concluded that DNs should have prime responsibility for booking NTS exit capacity in the event of DN sales. Under these proposed arrangements, DNs and NTS direct connects (who would interface with the NTS through their shippers) would receive equal treatment in the capacity allocation process of NTS capacity.

9.13 In the Offtake RIA, the cost benefit analysis quantified the likely benefits attributable to each of the three alternative options (Option2, Option 3, and Option 4) relative the arrangements that would most closely resemble current arrangements in the event of DN sales - Option 1. The three categories of benefit quantified were:

- reduced potential for discrimination between IDNs and RDNs;
- reduction in regulatory involvement; and
- efficient and economic operation and development of networks.

9.14 However, for the purposes of the Final IA, it is necessary to consider the costs and benefits of the proposed framework relative to the status quo. Reconsideration of the benefit areas above demonstrates that the option proposed (Option 2) serves to mitigate the costs that would otherwise arise were

DN sales to proceed with current arrangements largely unchanged. However, under the status quo, the absence of RDNs and IDNs means that a number of these costs are not currently incurred:

- Reduced potential for discrimination: Under Option 1 there would be the potential for the NTS to discriminate in the allocation of NTS exit capacity between IDNs and RDNs. However, in a no DN sales world, RDNs and IDNs do not exist, and there is therefore no scope for Transco to discriminate between them.

- Reduction in regulatory involvement: The Offtake RIA argued that the capacity allocation process implied by Option 1 would have the potential for generating disagreements between the DNs and the NTS on the level of MDQ that is consistent with the 1 in 20 obligation and therefore require a significant level of ongoing regulatory involvement. However, in a no DN sales world, the DNs and the NTS would be part of the same corporate entity. As such, relative to the current arrangements, the proposed offtake arrangements (as defined by Option 2) may *increase* regulatory involvement. The increased regulatory resources required by Ofgem, in the event of DN sales are considered in Chapter 9.

- Efficient and economic operation and development of networks: Under Option 1, the NTS would determine the level of NTS exit capacity provided at each offtake point, following a request for exit capacity from the DNs. Under this approach, there might be a natural tendency for a DN to "over-request" exit capacity leading to over-investment in the NTS. However, under the no sale option, the incentives between the DNs and the NTS are aligned, and such over-investment does not occur. However, Ofgem is of the view that investment signals under Option 2 would be superior to those under the status quo. The associated benefits are considered further below. Therefore the totality of the benefits assessed relative to Option 1 cannot all be applied within the Final IA.

9.15 In Ofgem's view, Option 2 is likely to yield positive benefits relative to the status quo in the following areas:

- Reducing undue discrimination: Under Option 2 both DNs and NTS direct connect shippers would be able to request the level of NTS exit capacity that they require rather than having this determined following negotiation with the NTS. This approach would therefore remove the scope for undue discrimination between DNs and other loads connected to the NTS.

- Efficient and economic operation and development of networks: Option 2 would promote the more efficient allocation of NTS exit capacity across NTS offtakes relative to the status quo option. Under DN sales, the proposed framework would therefore deliver more efficient signals for investment, particularly in relation to NTS direct connects. The associated benefit is quantified at £4.9m PV. This estimate is based on the assumption that 3.5% of NTS exit capacity related capex could be saved on an annual basis as a result of improved efficiency signals[57].

- Effect on competition: the removal of undue discrimination between NTS direct connects and DNs should deliver a framework in which there would be effective competition between all customers of the NTS.

- Security of supply: the improvement in investment signals discussed above should also have positive benefits for security of supply.

Diurnal storage and operational flows

9.16 As discussed in Chapter 5, in the Offtake arrangements conclusions document, the Authority concluded that an alternate "hybrid" approach to diurnal storage should be adopted. Under these proposed arrangements, a commercial

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[57] The analysis undertaken is based on data extracted from NTS exit capacity capex provided by Transco, relating to the period 2005-2012. Following Transco's suggestion, it is assumed that annual NTS exit capacity over the period 2013 – 2022 equals the average of the period 2005 – 2012 (i.e. £12.4 per annum). A discount rate of 6.25% has been applied to the benefits accruing over the period 2005/6 to 2022/23, discounted to 2004.

approach to the allocation of diurnal storage would be adopted, whilst ensuring that diurnal storage and NTS offtake flexibility would remain a service provided by the NTS to NTS connectees (i.e. DNs and NTS direct connects). Such a set of arrangements, however, would not involve DN shippers.

9.17 In the Offtake RIA, this hybrid model was not considered. However, the cost benefit analysis performed considered the potential for benefits in the following areas:

- gas balancing;
- electricity balancing;
- reduction in regulatory involvement; and
- reduced potential for undue discrimination between IDNs and RDNs.

9.18 The Offtake RIA considered the potential benefits of the two alternative options for diurnal storage against each other. However, for the purposes of the Final IA, it is necessary to consider the potential benefits that would apply relative to the status quo. Given this, a number of the potential benefits assessed within the Offtake RIA need to be reconsidered. We do this for each of the potential benefit areas quantified within the Offtake RIA in turn below.

Gas balancing

9.19 The money that is paid to (or paid by) NGT as a result of imbalance charges, scheduling charges and purchases and sales of gas for balancing purposes is returned to (or paid by) shippers via the balancing neutrality charge. These aggregate system payments are returned to (or paid by) shippers on the basis of their throughputs (i.e. the sum of their inputs and outputs).

9.20 Under a commercial framework for diurnal storage, as proposed, flexibility of offtake from the NTS would be allocated on an efficient (non-discriminatory) basis across all offtake points, and offtake restrictions would be more rigorously enforced than at present. The enforcement of gas offtake restrictions would have the potential to lower the costs incurred by NGT in its role as residual balancer.

If the flexibility restrictions are not enforced, NGT may, on occasion, have to undertake balancing trades that would not necessarily be reflected in the deviating party's end of day gas position. This implies that the costs of these trades caused by individual shippers could only be recovered from the generality of shippers through the neutrality charge. Hence the size of balancing charges paid (or returned) to shippers through the balancing neutrality charge may potentially be reduced (or the level of charge returned increased).

9.21 In the Offtake RIA, Ofgem quantified the net impact of this effect on the balancing neutrality charge by assuming that increased efficiency of NGT's balancing actions will reduce the cost of those balancing actions that result in costs to shippers. To obtain an estimate of the size of this impact, NGT analysed daily balancing neutrality charge data from 2002 and 2003 (provided by NGT). The sum of charges from days in which NGT's actions resulted in a balancing neutrality charge "cost" to shippers totalled £33.1m on average over the two years[58]. Ofgem considers that the greater efficiency of NGT's balancing actions that is expected to result from the proposed framework has the potential to reduce the cost of these actions by approximately 1% (equalling an annual benefit of £0.3m to shippers in nominal terms). Consistent with the analysis in the rest of this RIA, in calculating the present value of this benefit, a discount rate of 6.25% has been applied to the benefits accruing over the period 2005/6 to 2022/23, discounted to 2004.

9.22 The value of this in terms of reduction in the cost element of the balancing neutrality charge (in present value terms) is estimated at £3.4m in 2004 prices.

Electricity balancing

9.23 Under the proposed framework for diurnal storage / NTS offtake flexibility, in the event of DN sales, the flexibility of offtake from the NTS would be allocated on an efficient (non-discriminatory) basis across all offtake points. This should

[58]Transco actions led to aggregate balancing neutrality payment to shippers of £0.5m and £16.2m in 2002 and 2003 respectively. In 2002 daily actions by Transco resulting in "costs" to shippers totalled £34.9m, and those resulting in "payments" to shippers totalled £35.4m. In 2003, these figures were £31.4m and £47.6m respectively.

result in flexibility in offtake being allocated to those NTS direct connects who valued it most.

9.24 Ofgem considers that this will have a tangible impact in the electricity market, as a more appropriate allocation of scarce flexibility could result in more flexibility being offered into the electricity balancing mechanism. In turn, this could reduce the balancing costs incurred by the System Operator (in that it is likely that this could lead to more efficient and flexible gas fired electricity generators acquiring NTS flexibility over less efficient generators).

9.25 The total present value of reduction in balancing costs has been calculated as being the reduction in cost of accepted offers plus the increase in the revenue from bids accepted. The level of balancing cost relating to the acceptance of bids and offers from gas fired BM units over the period 2005/6 to 2022/23 has been assumed to equal the average of the period 2002-2004[59]. It is assumed that the ongoing balancing costs associated with gas fired generation are £11.9m p.a. and that these are reduced slightly on account of non-discriminatory allocation of scarce NTS flexibility.

9.26 Once again, in calculating the present value of this benefit, a discount rate of 6.25% has been applied to the benefits accruing over the period 2005/6 to 2022/23, discounted to 2004.

9.27 Ofgem considers that increased flexibility offered into the electricity balancing mechanism could have the effect of reducing balancing costs related to gas fired generation by as much as 1%. The value of this in terms of reduction in total balancing costs (in present value terms) is illustrated in Table A.16.

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[59] Source: ELEXON

Table A.16: Potential reduction in electricity balancing costs, relative to the status quo

	Proposed framework
Reduction in cost of offers accepted	£3.3m
Increase in revenue from bids accepted	£2.1m
Total present value of reduction in balancing costs	**£5.4m**

Potential reduction in regulatory involvement

9.28 An additional category of potential benefit quantified within the Offtake RIA with respect to diurnal storage is a reduction in the requirement for ongoing regulatory involvement relative to Option 1. The Offtake RIA argued that under an Option 1 approach there would be a significant risk of dispute over allocations, which would have the potential to increase the level of ongoing regulatory involvement. Furthermore, the Offtake RIA also argued that a commercial approach may reduce the level of regulatory resources that would be devoted to the price control process, particularly with respect to determination of an efficient level of investment.

9.29 However, for the purposes of the Final IA, the same analysis cannot be applied. In a no DN sales world, the DNs and the NTS would be part of the same corporate entity. As such, relative to the current arrangements, the proposed arrangements for diurnal storage will not reduce regulatory involvement to the same extent as assumed within the Offtake RIA.

Reduced potential for discrimination between IDNs and RDNs

9.30 Under Option A, which was used as the reference case for the Offtake RIA cost benefit analysis of diurnal storage options, there would be the potential for the NTS to discriminate in the allocation of NTS flexibility between IDNs and RDNs.

To compensate for this potential discrimination, IDNs might therefore need to invest disproportionately more than they would otherwise have done.

9.31 However, for the purposes of the Final IA, the same analysis cannot be applied. In a no DN sales world, RDNs and IDNs do not exist, and as such, there is no scope for Transco to discriminate between them. As such, by eliminating the potential for discrimination between RDNs and IDNs, adoption of the proposed arrangements would mitigate the costs that would otherwise have occurred under DN sales.

Business separation

9.32 Proposals for the targeted structural separation of Transco's NTS business from its RDNs have been suggested in order to seek to ensure that there is no undue discrimination between RDN and IDN businesses. The Offtake RIA did not quantify the potential benefits of business separation. Furthermore, from a Final IA perspective, business separation proposals seek to mitigate the costs that may otherwise occur in the event of DN sales. In relation to a no-DN sales option, the potential benefits of business separation have therefore been assumed to be zero.

Interruptions arrangements

9.33 As discussed in Chapter 5, in the Interruptions arrangements conclusions document, the Authority concluded that in the event DN sales proceeds:

- for the allocation of NTS exit capacity, an unconstrained approach should be adopted for the long term, and a constrained approach for the medium and short term, consistent with Option 3; and
- for the allocation of exit capacity at DN level, the status quo (Option 1) would be retained in the near term. In the longer term, reform of the allocation of exit capacity at DN level would be addressed (though not in the context of DN sales) along the lines of an unconstrained approach to

capacity allocation with a matrix approach for interruption – potentially on the basis of an Option 2A model and approach.

9.34 However, in the Interruptions RIA, the cost benefit analysis performed did not consider the potential benefits associated with the implementation of reform options that differed between the NTS and the DNs. As such, whilst the potential benefits associated with Option 3 were considered, this was with respect to Option 3 reform on both the NTS and DNs. The application of Option 3 reform to the NTS alone was not considered.

9.35 Within this Final IA, it is therefore necessary to reconsider the potential benefits that could arise from proposed reform to interruptions and the allocation of exit capacity such that the benefits associated with Option 3 reform on just the NTS are understood.

9.36 We have assumed, for the purposes of our analysis, that whilst retention of the 'status quo' at a DN level, in the event of DN sales, may involve some additional costs (as a result of the greater number of DNs involved and consequent increase in potential interfaces), the benefits relative to the status quo, are likely to be zero.

9.37 The Interruptions arrangements conclusions document proposed that the status quo arrangements for allocating DN exit capacity should remain but acknowledged the possibility of future reform on the DN network. However, the exact nature of such future reform has not been determined, and will be the subject of a separate cost benefit analysis in the future. As such, the quantification of DN reform is outside the scope of this cost benefit analysis.

Quantification of potential benefits

9.38 The Interruptions RIA considered two types of potential benefits when assessing the different options for reform proposed:

- ♦ Elimination of short-run inefficiency: reducing the total economic cost of interruption as customers that are more willing to be interrupted than others would be able to signal that willingness through the terms of the interruptible contract struck with Transco; and

- Elimination of long-run inefficiency: by encouraging the development of investment signals on the NTS, backed by financial commitments from the users of the NTS. These signals are expected to reduce the risk of stranded NTS assets and promote efficient NTS investment, by allowing the NTS to make efficient trade-offs between network investment, interruptions, and the use of local storage such as LNG.

9.39 In assessing the potential benefits, given the Authority's current proposals in this area, we have repeated the benefits analysis performed within the Interruptions RIA, where it related to reform on the NTS. We have therefore implicitly assumed that the potential relative benefits of the 'no sale option' arrangements in the event of DN sales and the current arrangements are the same.

9.40 Whilst Ofgem believes that some short-run efficiencies would result from the constrained (Option 3) reform proposed on the NTS, these will not be of the same scale as the equivalent benefits should DN reform proceed. The analysis within the Interruptions RIA focused on the potential short-run efficiency benefits relating to DN interruptions, and therefore, for consistency with this approach, any potential NTS related benefits in this area have not been quantified.

9.41 The Interruptions RIA assumed that long-term inefficiency would manifest itself in capital expenditure on both the distribution networks and the NTS. Therefore, given the proposals now adopted, we have applied the same methodology used in the Interruptions RIA to NTS capital expenditure in isolation:

- NTS exit capacity capex is assumed to be £12m per annum in current prices; and

- Sharper investment signals and more flexible contracting arrangements for interruptible services are assumed to deliver benefits of at least 3% of capital expenditure per annum.

9.42 The implications of these assumptions, given that an assumed discount rate of 6.25% has been applied to the benefits over the period 2005/6 to 2022/23 discounted to 2004, is that the PV of expected benefits would be £3.6m.

Benefits not quantified

9.43 As stated above, likely short-run efficiencies have not been quantified for the purposes of this Final IA. There are also a number of other potential benefits that have not been quantified, as identified within the Interruptions RIA. These include:

- ♦ Promotion of economy and efficiency, with respect to reduction in the potential for undue discrimination (by eliminating the potential for the differential treatment of existing customers and new customers seeking to gain access to the network under current arrangements), and increased freedom to contract;
- ♦ Security of supply, both long-term through generating more accurate investment signals and short-term by facilitating liquid and transparent markets for network interruption and short term capacity such that the NTS can efficiently manage constraints;
- ♦ Increased customer choice: by allowing NTS customers more choice in their terms of interruption; and
- ♦ Beneficial effects on competition including competition in interruptions (by encouraging more participants to offer interruptible services as a result of the greater flexibility of terms allowed), and competition in wholesale electricity (by making the price of interruptions more reflective of the actual quantity of interruptions, and the value attributed to them).

Appendix 10 Implications for merger policy

10.1 The Final IA assesses the quantum of potential benefits that Ofgem believes could accrue to customers on account of comparative regulation between separately owned distribution businesses. A key assumption in this evaluation is that benefits to customers are positively related to the number of comparators i.e. the greater the number of comparators, the greater the customer potential benefits. This is consistent with the accepted assumptions in other regulated industries.

10.2 It follows, therefore, that should the number of comparators reduce on account of a merger or comparable transaction between two DNs, then it is likely that there would be a detriment to customers. Ofgem provided a position paper to the DISG on 6 July 2004[60] which stated that were there, in future, to be a merger or comparable transaction between two or more DNs, then Ofgem would seek to modify the licences of each company in the merged group to reduce the regulated revenue. This reduction in revenue would seek to pass back to customers the costs associated with the loss of a comparator. This policy largely replicates that applied to mergers in the electricity distribution sector and facilitates regulatory consistency. However, it should be noted that the method of recovering the value of a comparator established may change as this is currently the subject of an Ofgem review[61].

10.3 In the position paper, Ofgem also stated that the precise details, including level of the reduction in the regulated revenue, would be derived at the time when the merger or comparable transaction is proposed.

10.4 Throughout the analysis on the potential costs and benefits for the Final IA, Ofgem has sought to make conservative assumptions with a view to ensuring

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60 *"Ofgem policy on future mergers of gas distribution networks",* Ofgem, 6 July 2004.
61 As outlined in Electricity Distribution Price Control Review, Update paper, Ofgem, September 2004.

that existing and future customers' interests are protected were DN Sales to proceed. Hence, in an evaluation of the level of the reduction in the regulated revenue that should be applied to a merged entity, Ofgem expects to continue to make assumptions of a conservative nature. Therefore, as a starting premise, in reaching an evaluation, Ofgem expects (in order to ensure adequate protection to customers) that the benefits of comparative regulation are as per the high case assumptions set out in the Final IA.

10.5 The scale of these numbers reflects the significant potential benefits that Ofgem believes may be realised as a result of DN sales through the creation of independent comparators. In Ofgem's view, these potential benefits would be significantly undermined, were the number of comparators to be reduced through subsequent mergers.

Appendix 11 Background to potential costs chapter

11.1 A number of studies have been commissioned by the industry in an effort to quantify the possible net customer benefit that a potential DN sale may yield. This appendix provides:

- an overview of previous surveys completed by ILEX in November 2003 and OXERA in May 2004; and
- an overview of the costs identified by Ofgem in the Agency & Governance, Roles & Responsibilities, Offtake arrangements and Interruptions arrangements RIAs.

Previous surveys

11.2 Table A.17 below provides the table outlined in Chapter 9 and highlights the headline figures that were obtained through the completion of previous surveys:

Table A.17: Previous cost estimations

Survey completed by	High level cost estimation (PV)
ILEX	£38 to £55 million
OXERA	£43 to £729.5 million

ILEX shipper survey

11.3 To achieve an improved understanding of the likely net customer benefit that would accrue following a potential DN sale, in November 2003 Ofgem commissioned ILEX to undertake a review of its preliminary RIA[62]. On completion of its analysis, ILEX produced a final PV cost estimation of the impact on shippers in the region of £38 to £55 million. It considered that this level of costs would be incurred irrespective of the number of DNs that NGT decides to sell.

11.4 In completing this review ILEX compared a base scenario, in which NGT would retain all of its DNs, with a scenario in which one or more DNs would be sold to an independent party. ILEX assumed, in making this comparison, which potential costs associated with reform of the supply point administration (SPA), interruptions and exit arrangements would not be impacted by the outcome of the DN sales project.

11.5 To reach an estimate of the likely costs that would be incurred by the industry, ILEX reviewed the submissions to the consultation document, published by Ofgem in July 2003. Following analysis of these responses, where necessary, ILEX held meetings with respondents to achieve an improved understanding of the cost drivers behind the figures quoted. In addition, ILEX liaised with various IT developers to ascertain the likely costs of the system development. The final estimates presented by ILEX were therefore reached through a combination of these meetings and ILEX's expertise in this area.

11.6 ILEX assumed, when estimating costs, that minimum changes to the current regime would be necessary and that, in line with this, minimum costs would be incurred by the industry. In this respect, additional costs faced by NGT in relation to the implementation of amended arrangements to support the potential sale of one or more of its DNs were not included in the estimates. ILEX assumed that the decision to sell had been motivated by an anticipated commercial benefit and that these costs should not therefore be passed through to customers as a result of the sale.

11.7 The figures developed, as part of the study, were separated into:

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[62] *National Grid Transco – Potential sale of network distribution businesses: Next steps*, Ofgem, November 2003, 170/03

- one-off costs; and
- on-going costs.

11.8 Within these categories, the figures were further broken down into costs associated with appointing IT contractors, lawyers, consultants and regulatory persons. In terms of cost, ILEX assumed that one additional gas industry employee would cost £80,000 per annum with a lawyer costing £300,000 for the same period and an IT contractor charging £575 per day.

11.9 The total costs were also deflated to 2000 prices to allow a direct comparison with the level of benefits estimated by ILEX as these were calculated using controllable operating expenditure at 2000 prices as a basis.

11.10 The model that ILEX developed assumed, in relation to the DN sales process, that the cost incurred by shippers would be directly related to their size, in view of the fact that larger shippers have more complex systems in place. The costs were therefore estimated for single shippers and scaled up to represent the entire market using the assumption that twelve small, seven medium-sized and twelve large shippers currently operate in the gas market.

11.11 Following the derivation of cost estimates, ongoing costs were converted into NPVs to illustrate total cost over the life time of the systems. This calculation was undertaken assuming that costs would be incurred from 2006 for a period of 17 years and, using a discount rate of 6.25%.

11.12 ILEX produced a final NPV estimate of the impact on shippers in the region of £38m to £55m which stated that this level of costs would be incurred irrespective of the number of DNs that NGT committed to sell.

OXERA's survey

11.13 In response to the publication by Ofgem, in April 2004, of its RIA regarding the options for the development of Agency & Governance arrangements[63] to facilitate a potential DN sale, the Gas Forum commissioned OXERA to undertake an independent examination of the costs and benefits associated with the options proposed. The results of this survey were published in May 2004.

11.14 In developing the survey OXERA set out four (well-defined) options in relation to the scope of the Agency and requested that shippers provide estimates of the likely costs incurred under each scenario. The four scenarios considered by OXERA covered a spectrum of options, including both a broad Agency and full fragmentation model with the two remaining options representing a compromise between these extremes. Despite the range of scenarios upon which the cost estimates were based, none of these exactly replicated Option C that the Authority concluded to adopt.

11.15 The survey completed by OXERA highlighted that the proposals regarding the creation of an Agency would serve to reduce significantly costs incurred by shippers as a result of the potential sale of one or more of Transco's DNs. OXERA estimated that if the industry were allowed to fragment fully, shippers would be exposed to costs of up to £729.5 million while under the broad Agency option, the costs were estimated at £43 million. Under the two further options in which the Agency would be developed but its scope reduced relative to the broad Agency, the costs were estimated to be between £87.9 million and £98.8 million. These options roughly approximated the scope of the Agency decided upon by the Authority as represented by Option C.

11.16 The survey was structured to allow shippers to identify one-off system implementation costs separately to costs that shippers would anticipate to be ongoing. The survey also requested that shippers identify the most significant driver of costs in each area.

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[63] National Grid Transco – Potential sale of network distribution businesses, Agency and governance arrangements. Regulatory Impact Assessment 83/04

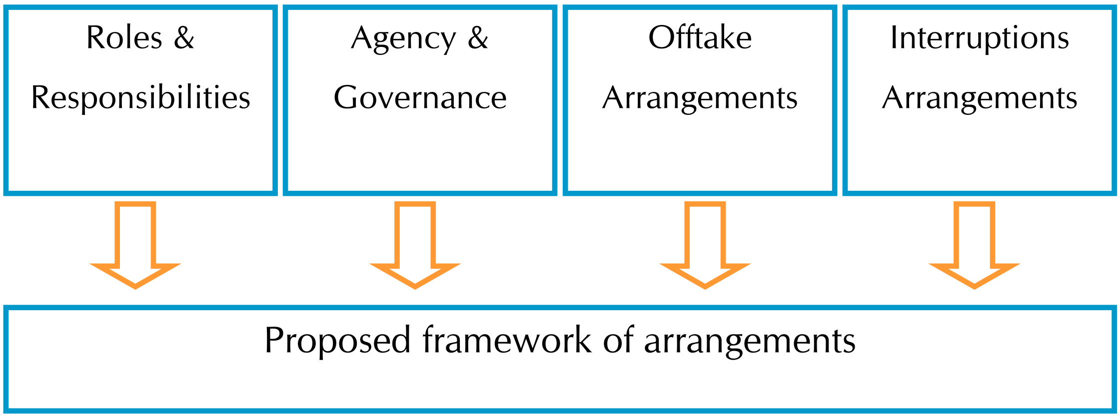
11.17 The pro forma was issued to thirteen gas shippers and submissions were received from seven respondents, of which, these represent 70% of the domestic gas market and a 'high share' of the industrial and commercial market. In total, the respondents were responsible for supplying 15.5 million supply points across the gas market, out of an assumed total of 21 million. An estimate of costs for the total market was obtained by pro-rating costs submitted with respect to the total number of supply points.

11.18 Using the data submitted by shippers, the PV of the costs was calculated assuming a discount rate of 6.25% for the period until 2022. High level figures indicated that costs incurred would vary widely dependent on the scope and form of the Agency implemented.

Costs identified in Ofgem RIAs

11.19 Since April 2004 Ofgem has produced four RIAs with the intention of evaluating the potential impact of arrangements implemented, following the sale of one or more of NGT's DNs, and determining estimates of the likely level of costs that would be incurred under each proposed scenario. These RIAs were also intended to inform Ofgem's completion of the Final IA regarding the potential net benefits (or costs) that may be incurred by the industry, and ultimately consumers, following the proposed DN sale. Figure A.7 below provides an illustrative overview of the process followed.

Figure A.7: Structure of the consultation process in relation to the potential sale of one or more of NGT's DNs



11.20 Within these RIAs an estimate was arrived at regarding the overall potential quantitative benefits that Ofgem would expect the industry to incur in relation to the proposals presented, relative to the no sale option. An evaluation of the potential qualitative costs and benefits, arising from the sale, was also included highlighting the areas in which Ofgem would anticipate that industry participants would incur additional costs.

11.21 This section provides an overview of the qualitative analysis undertaken by Ofgem as part of each RIA. An evaluation of the likely cost associated with each of the options proposed was undertaken within each RIA. This section only includes a discussion of the potential costs relating to the option chosen by the Authority as part of the indicative decisions they have reached with respect to DN sales. A full explanation of the methodology used by Ofgem, in developing its analysis of the costs which could be potentially incurred in the event of a DN sale, can be found in each of the RIAs on Ofgem's website[64].

[64] National Grid Transco – Potential sale of gas distribution network businesses, Allocation of roles and responsibilities between transmission and distribution networks, Regulatory Impact Assessment, Ofgem, April 2004, 84/04; National Grid Transco – Potential sale of gas network distribution businesses, Agency and governance arrangements, Regulatory Impact Assessment , Ofgem, April 2004 83/04; National Grid Transco – Potential sale of gas distribution network businesses, Offtake Arrangements, Regulatory Impact Assessment, Ofgem, June 2004, 131/04 and National Grid Transco – Potential sale of gas network

Agency & Governance RIA

11.22 To obtain an improved understanding of the potential quantitative costs which could be incurred with respect to implementation of the proposed arrangements set out in the Agency & Governance RIA, Ofgem issued a pro forma to shippers in March 2004. The pro forma included a detailed list of the possible functions that an Agency could adopt and asked shippers to estimate the likely cost impact of this. The submissions allowed Ofgem to collate figures regarding the extent to which increases in the cost of services provided by DNs and Transco, as a result of the DN sales process, could be mitigated by the establishment of an Agency responsible for the provision of these services.

11.23 The pro forma was sent to eleven gas shippers and responses were received from eight. The pro forma responses highlighted that costs could be substantially reduced by the establishment of an Agency in a post-DN sales environment which would ultimately afford significant cost savings for customers.

11.24 While some shippers were confident that more significant cost savings would be achievable when the role of the agent was as broad as possible, others noted that the broad Agency option would not assist any material cost savings over and above the remaining options proposed by Ofgem.

11.25 In order to further its understanding, as part of the RIA Ofgem also undertook qualitative analysis of the potential costs as a result of proposals regarding the Agency & Governance arrangements necessary to accommodate the DN sales process. Ofgem identified that shippers could incur costs with respect to:

- fragmentation of credit and cash collection;
- the blurring of accountability for the collection of operational data in relation to AT-link and RGTA; and

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distribution businesses, Interruptions Arrangements, Regulatory Impact Assessment, Ofgem, June 2004 146/04

- the reduction in comparative regulation.

11.26 With respect to the fragmentation of credit and cash collection, Ofgem outlined that shippers are frequently required to put arrangements in place with new counterparties and that associated costs are therefore expected to be minimal. Furthermore, it is noted that whilst the comparative regulation benefits through creation of an Agency are expected to be less than those without an Agency, these potential additional benefits would be significantly outweighed by the potential costs associated with a "no Agency" solution.

Roles & Responsibilities RIA

11.27 Within the Roles & Responsibilities RIA Ofgem identified a number of areas in which it may be anticipated that costs associated with the potential sale of one or more of Transco's DNs are likely to occur. Ofgem detailed that costs may occur in relation to:

- the loss of economies of scale;
- a reduction in accountability during the transition period;
- the loss of operational synergies; and
- the potential for industry fragmentation.

11.28 However, an examination of these areas highlighted that although some costs may be incurred in this respect they are unlikely to be significant or could be reduced by additional arrangements which could be implemented as part of DN sales.

11.29 Potential costs associated with the loss of economies of scale could arise as a result of NGT's decision to sell one or more of its DNs which Ofgem considers to be motivated by an anticipated commercial benefit. Ofgem is therefore of the opinion that that these costs should not be passed through to customers as a result of the sale.

11.30 The reduction in accountability, detailed above, is expected to arise from the SOMSA agreement governing the provision of area control centre services from NGT to the DNs for a transitional period. In this respect there would be some divergence between the party responsible for area control centre functions and the party that actually performs this role. Ofgem considers that associated potential costs would, however, be minimal as it is anticipated that NGT's role would largely involve operating the relevant systems under instruction from the relevant DN. Although, it was noted that minor costs may arise as a result of the potential for NGT to discriminate in favour of its RDNs.

11.31 Some workgroup participants considered that a loss of operational synergies may result from:

- separate operation of gas balancing and DN congestion balancing due to the extent to which these overlap; and
- the fragmentation of the Gas National control Centre (GNCC).

11.32 However, Ofgem considered that it would be possible to separate the roles associated with gas balancing and DN congestion balancing with minimal implications for costs to customers whilst also highlighting that the GNCC is currently operated separately by NGT from each DN control centre. Therefore, Ofgem did not envisage that significant additional costs to customers are likely to be incurred in this area.

11.33 With respect to the potential for industry fragmentation, concerns were expressed that the Roles & Responsibilities option chosen by the Authority would create a relatively active DN and that this may allow DNs to establish diverging Network Code and charging arrangements. Ofgem however, considered that appropriate Agency and governance arrangements are likely to ensure that this would not be the case.

Offtake arrangements RIA

11.34 The offtake arrangements RIA sought to quantify potential costs and benefits associated with proposed arrangements to support:

- the booking of exit capacity;
- diurnal storage and operational flows; and
- the necessary business separation required between NGT and RDNs.

Booking of exit capacity

11.35 The RIA highlighted that, relative to the status quo, limited costs are likely to be incurred with respect to implementation of the NTS connects booking model to support the proposed exit capacity arrangements. In the RIA, Ofgem detailed that some degree of implementation costs may be incurred by the industry and noted that while NTS exit capacity is currently determined centrally at each offtake point, following a potential DN sale, DNs would be responsible for setting NTS exit capacity individually. However, Ofgem also highlighted that, as DNs already compile ten year demand forecasts, the resource necessary to assess the required level of exit capacity already exists at a DN level and therefore additional costs incurred should not be significant.

Diurnal storage and operational flows

11.36 The RIA proposed two options with respect to diurnal storage and operational flows. The first proposed retaining arrangements that resemble the status quo, while the second was based on market principles. Following industry consultation the Authority reached the decision that, in relation to diurnal storage, a hybrid of the two models proposed should be implemented.

11.37 Under option A, Ofgem identified that costs may arise in three main areas:

- NGT is proposed to be given responsibility for setting the level of diurnal storage and operational flows and, as such, this could potentially allow it to unduly discriminate between IDNs and RDNs in the allocation of secondary NTS exit capacity rights in both the short and long term;
- diurnal storage is proposed to be defined as an operator to operator product and therefore exclude the potential for NTS direct connects to reveal the value that they place on flexibility; and

- a significant risk of dispute may be present and this could increase the need for regulatory involvement and therefore potentially increase costs.

11.38 With respect to the proposals regarding option B, Ofgem identified that the biggest cost that would arise would be associated with the magnitude of change required to support these arrangements.

11.39 In order to minimise the costs identified under option A and option B, a hybrid of the two models was proposed which, Ofgem anticipated, would be developed through the workgroup processes. As a result, quantification of the potential costs associated with the modification of diurnal storage to accommodate DN sales proved difficult in respect of the fact that the exact proposed arrangements to be implemented were not known.

Business separation

11.40 The offtake arrangements RIA considered the form of separation to be put in place to mitigate the risk of any undue discrimination by Transco between IDNs and RDNs. This document also stated that any costs incurred by Transco in this respect should not be passed through to customers as a result of the sale. Ofgem considered that these costs are the result of NGT's commercial decision to sell some of its DNs, and as such should not be passed through to customers.

Interruptions arrangements RIA

11.41 The interruptions arrangements RIA stated that, under the proposed tender process for interruptions, costs were likely to be incurred as a result of the implementation of IT systems. Specifically, shippers and DNs were likely to be required to develop systems in order to be able to participate in the proposed tender process for interruptible capacity which will be more costly to implement than the status quo.

11.42 In addition, the workgroup process has highlighted that the proposed tender process could require shippers to form a view on the value of interruptions (which may lead to additional costs above those currently incurred).

Appendix 12 Copy of the shipper cost pro forma

Cover sheet

Key

	Cells requiring data entry
	Cells with hard-coded formulae

Note, this proforma should be completed only after reading the following two documents:

(1) proforma questionnaire guidance document; and
(2) assumptions document

Units
All cost figures should be stated in £k, 2004 prices
All employee number figures should be stated in FTEs

Additional commentary
Additional detailed commentary / justification should be provided
Where appropriate, this can be provided within this spreadsheet, however,
use of supplementary word documents may be more appropriate in many cases.

Business characteristics

Company name	

		units
Number of domestic supply points served (i.e. supply points with annual consumption <2500 therms)		No. of supply points
ıber of small non-domestic supply points served (i.e. supply points with annual consumption 2,500 - 50,000 therms)		No. of supply points
Number of large non-domestic supply points served (i.e. supply points with annual consumption >50,000 therms)		No. of supply points
Total number of supply points	0	No. of supply points
Number of supply points covered by multi-site contracts		No. of supply points
Number of supply points directly connected to the NTS		No. of supply points
Number of DN regions where shipper business has a presence		No. of DNs

Additional commentary

Agency & governance (and Roles & Responsibilities) -

Up-front net implementation costs

		units
IT systems costs		£k, 2004 prices, (net benefits to be shown as negative numbers)
Staff costs		£k, 2004 prices, (net benefits to be shown as negative numbers)
Other costs		£k, 2004 prices, (net benefits to be shown as negative numbers)
Total net up-front inplementation costs	0	£k, 2004 prices, (net benefits to be shown as negative numbers)

Staff costs:		
Number of additional FTEs		FTEs
average cost per FTE	#DIV/0!	£k, 2004 prices, (net benefits to be shown as negative numbers)

Ongoing net annual costs

		units
IT systems costs		£k per annum, 2004 prices (net benefits to be shown as negative numbers)
Staff costs		£k per annum, 2004 prices (net benefits to be shown as negative numbers)
Other costs		£k per annum, 2004 prices (net benefits to be shown as negative numbers)
Total ongoing net annual costs	0	£k per annum, 2004 prices (net benefits to be shown as negative numbers)

Staff costs:		
Number of additional FTEs		FTEs
average cost per FTE	#DIV/0!	£k, 2004 prices

Additional commentary

Offtake arrangements -

Up-front net implementation costs

		units
IT systems costs		£k, 2004 prices, (net benefits to be shown as negative numbers)
Staff costs		£k, 2004 prices, (net benefits to be shown as negative numbers)
Other costs		£k, 2004 prices, (net benefits to be shown as negative numbers)
Total net up-front inplementation costs	0	£k, 2004 prices, (net benefits to be shown as negative numbers)

Staff costs:		
Number of additional FTEs		FTEs
average cost per FTE	#DIV/0!	£k, 2004 prices, (net benefits to be shown as negative numbers)

Ongoing net annual costs

		units
IT systems costs		£k per annum, 2004 prices (net benefits to be shown as negative numbers)
Staff costs		£k per annum, 2004 prices (net benefits to be shown as negative numbers)
Other costs		£k per annum, 2004 prices (net benefits to be shown as negative numbers)
Total ongoing net annual costs	0	£k per annum, 2004 prices (net benefits to be shown as negative numbers)

Staff costs:		
Number of additional FTEs		FTEs
average cost per FTE	#DIV/0!	£k, 2004 prices

Additional commentary

Interruptions arrangements -

Up-front net implementation costs

		units
IT systems costs		£k, 2004 prices, (net benefits to be shown as negative numbers)
Staff costs		£k, 2004 prices, (net benefits to be shown as negative numbers)
Other costs		£k, 2004 prices, (net benefits to be shown as negative numbers)
Total net up-front inplementation costs	0	£k, 2004 prices, (net benefits to be shown as negative numbers)

Staff costs:		
Number of additional FTEs		FTEs
average cost per FTE	#DIV/0!	£k, 2004 prices, (net benefits to be shown as negative numbers)

Ongoing net annual costs

		units
IT systems costs		£k per annum, 2004 prices (net benefits to be shown as negative numbers)
Staff costs		£k per annum, 2004 prices (net benefits to be shown as negative numbers)
Other costs		£k per annum, 2004 prices (net benefits to be shown as negative numbers)
Total ongoing net annual costs	0	£k per annum, 2004 prices (net benefits to be shown as negative numbers)

Staff costs:		
Number of additional FTEs		FTEs
average cost per FTE	#DIV/0!	£k, 2004 prices

Additional commentary

Total costs -

Up-front net implementation costs

		units
IT systems costs	0	£k, 2004 prices, (net benefits to be shown as negative numbers)
Staff costs	0	£k, 2004 prices, (net benefits to be shown as negative numbers)
Other costs	0	£k, 2004 prices, (net benefits to be shown as negative numbers)
Total net up-front inplementation costs	0	£k, 2004 prices, (net benefits to be shown as negative numbers)

Staff costs:		
Number of additional FTEs	0	FTEs
average cost per FTE	#DIV/0!	£k, 2004 prices, (net benefits to be shown as negative numbers)

Ongoing net annual costs

		units
IT systems costs	0	£k per annum, 2004 prices (net benefits to be shown as negative numbers)
Staff costs	0	£k per annum, 2004 prices (net benefits to be shown as negative numbers)
Other costs	0	£k per annum, 2004 prices (net benefits to be shown as negative numbers)
Total ongoing net annual costs	0	£k per annum, 2004 prices (net benefits to be shown as negative numbers)

Staff costs:		
Number of additional FTEs	0	FTEs
average cost per FTE	#DIV/0!	£k, 2004 prices

Additional commentary

Appendix 13 Guidance document issued alongside shipper cost pro forma

Background

In April 2004, following the Authority's decision that work should proceed on DN sales, Ofgem issued two Regulatory Impact Assessments (RIAs) for consultation. The first RIA concerned the allocation of roles and responsibilities between NTS and DNs, with the second describing options for the form of Agency and governance arrangements. In June 2004, Ofgem published an RIA that outlined options for the offtake arrangements and, later the same month, a fourth RIA was published, which focused on an appropriate form for the interruption arrangements.

Following consultation, decisions on the two April RIAs were published in May 2004, and decision documents for the two June RIAs were published on 13 August 2004.

Ofgem is now in the process of developing a Final RIA, which will consolidate these decisions and provide an overall cost benefit analysis on the sale of DN networks relative to the current status quo. Ofgem intends to release this document in late September 2004. The Authority will subsequently consider whether to consent to a disposal of the DN assets at its November 2004 meeting.

In issuing this document, it is important to make clear that there can be no expectation on the part of National Grid Transco, Transco plc, potential DN purchasers, shippers or other interested parties either as to what the Authority's final decisions in relation to the proposed transaction may be, or as to the regulatory framework that may be implemented if the Authority consents to the proposed transaction. The information contained in this paper is not binding on the Authority. Nothing in this paper is to be construed as granting any rights or imposing any obligations on the Authority. The Authority's discretion in this matter will not be fettered by any statements made and all references to the decisions and conclusions by the Authority are qualified by this statement.

Purpose

The Final RIA will:

- describe the options that would be implemented in the event that the sale of one or more DNs takes place, within an overall framework that is consistent with the approaches set out in the RIA decision documents; and
- present a final qualitative and quantitative cost benefit analysis, evaluating the NPV impact of the selected framework relative to the current status quo.

Therefore in developing the Final RIA, Ofgem will need to consider the costs that would be incurred should the proposed framework be implemented. To this end, Ofgem has, in conjunction with shippers, developed a pro forma through which relevant and detailed information regarding potential shipper costs can be provided to Ofgem.

This document:

- outlines the principles that have been applied in developing this pro forma;
- provides high-level guidance to ensure consistency of approach across submissions; and
- provides an overview of the information requested within the pro forma as well as more detailed completion guidance.

Principles

The attached pro forma has been developed to enable Ofgem to gain an understanding of the implications of the potential sale of one or more DNs for shipper costs and the associated arrangements proposed in the event of sale.

This pro forma has been developed in conjunction with shippers to:

- ensure high-level consistency across submissions; whilst
- recognising the differing characteristics of shipper businesses and therefore allowing some freedom in the format and disaggregation of detailed cost data and assumptions provided.

Ofgem recognises that in order to provide detailed and consistent cost estimates, shippers need to understand, in detail, the implications of the specific arrangements proposed for their business. To this end, Ofgem has drafted an assumptions document that summarises the arrangements proposed in each of the four RIA decision documents, and then details the specific implications for the shipper community.

This assumptions paper represents an important reference that should be read and understood before the pro forma is completed.

High-level guidance

When completing the pro forma, shippers should:

- consider the potential impact on ***their business alone*** – the costs incurred by other shippers, the Agency, NGT or Ofgem should not be estimated as part of this submission;
- quantify the cost implications of those measures ***as defined within the assumptions paper***;
- estimate the costs incurred ***relative to the current arrangements*** in place, and as such 'net off' any benefits that may result from implementation of the proposed framework, for example, if the proposals require an additional 2 FTEs, yet replace a current process requiring 1 FTE, then the net impact is an additional 1 FTE. Furthermore, net benefits should be expressed as negative figures;

- quantify the cost implications associated with the ***sale of four distribution networks*** (with the commentary providing details regarding the sensitivity of cost estimates to a different (smaller) number of distribution networks being sold);

- ***where certain key decisions have yet to be made***, please provide an estimate of the costs imposed by the ***lowest cost solution***, with estimation of the additional costs that would be incurred, should a more costly solution be adopted, provided in the commentary;

- provide cost estimates that represent the ***most likely outcome*** i.e. base case / median estimates – any worst case scenarios and assessment of risks should form part of the detailed commentary provided;

- distinguish between ***implementation (one-off)*** and ***ongoing costs***;

- ensure that the costs of introducing new systems and processes are only included where the introduction of such measures is **efficient and necessary**;

- ensure that ***costs are mutually exclusive* -** whilst the *pro forma* is split into sub-sections, care should be taken to ensure that costs are not repeated within different sub-sections generating an over-estimation of costs in aggregate. Where there are interactions / commonalities between areas, these should be noted within the commentary with detailed cross-references provided;

- submit costs in thousands of pounds ***(£k),*** specified in 2004 prices; and

- ***provide sufficient detail*** i.e. disaggregation of cost data / documentation of assumptions to allow an understanding of the derivation of high-level estimates, ideally providing:

    - cost drivers i.e. what causes costs to change (e.g. number of interfaces or degree of complexity);

    - a break down by cost category as appropriate (e.g. customer service, sales, transportation invoicing, credit cover, energy balancing, connection & site works, metering and overheads) as well as a more detailed explanation of what the costs represent; and

    - specification of whether costs would vary with the number of DNs sold.

Overview of pro forma

The pro forma has been structured into a number of sections, which include:

- business characteristics;

- Agency & governance (including the impact of roles & responsibilities);

- offtake arrangements;

- interruptions arrangements; and

- total cost impact.

Business characteristics

In the business characteristics section, we ask for a few details to allow the basic characteristics of the shipper business surveyed to be understood. These include:

- number of domestic supply points served (i.e. supply points with annual consumption of less than 2,500 therms);
- number of small non-domestic supply points served (i.e. supply points with annual consumption of 2,500 – 50,000 therms);
- number of large non-domestic supply points served (i.e. supply points with annual consumption of more than 50,000 therms);
- number of DN regions where shipper business has a presence;
- number of supply points covered by multi-site contracts; and
- number of supply points directly connected to the NTS.

If supply point data cannot be provided in the format requested, then data that approximates the format requested should be provided e.g. daily metered and non-daily metered supply points, with a note explaining the definitions applied.

The total number of supply points is automatically generated from the numbers provided within the yellow data fields. Please could you check this number for accuracy.

RIA specific sub-sections

Separate sections are specified relating to each of the four RIA decision documents published (roles & responsibilities, Agency & governance, offtake arrangements, and interruptions arrangements). However, it should be noted that the impact of the roles & responsibilities and Agency & governance costs should be considered together under a single heading.

The assumptions paper details the proposed arrangements in each of these areas, which should be assessed in relation to the arrangements currently in place.

Whilst the pro forma is structured into separate sections to allow easy cross-reference to the RIAs, there are interactions between some of these areas. As such, it may not be possible to cost the implications of each set of proposals in isolation.

The cost submissions should evaluate the cost of the single, consistent set of arrangements as described in the assumptions paper.

Care should therefore be taken that the costs submitted in one sub-section, are not repeated elsewhere leading to double-counting on aggregation. Where necessary, commentary should be provided regarding the interactions between each area and any adjustments made.

Within each area, the pro forma requests information on:

- net up-front implementation costs – these costs should be one-off in nature and non-recurring; and

- the net ongoing annual costs of operating under the proposed framework once they have reached a steady state.

Both the up-front implementation costs and ongoing operations costs are further disaggregated into the following sub-categories:

- IT systems costs;

- staff costs; and

- other.

Where applicable, benefits should be expressed as negative figures.

Further data fields have been added to allow the estimation of staff costs to be more fully understood. The number of additional FTEs required should be provided. The spreadsheet will then automatically generate the average cost per FTE on the basis of the staff cost total and FTE numbers submitted. Please could you sense check the number generated.

In general, white cells within the pro forma indicate cells where formulae such as totals have been hard-coded into the spreadsheet to ensure that the numbers provided reconcile. We would ask that you check the numbers that are generated to ensure that they accurately represent your views. Cells requiring data entry have been colour coded in yellow.

Total costs

The final sub-section of the pro forma aggregates the data provided to generate total costs for the proposed arrangements in the same format as above. The aggregation formulae have been hard-coded into the spreadsheet and therefore data entry should not be required. However, we ask you to sense-check the totals that result to ensure that they provide a reasonable estimate of total costs and that no double-counting of costs has occurred.

Detailed commentary

The data fields on the pro forma have been kept to a small number to reflect the differing characteristics and estimation methodologies of each shipper business. However, as a result, it is extremely important that there is sufficient documentation of the estimation methodologies and assumptions applied to allow Ofgem to understand the key cost drivers and any underlying differences in views between shippers.

We would therefore ask that the commentary provided is as detailed as possible. This can be provided either within the Excel pro forma or you may find word attachments to be more appropriate.

Ofgem would expect to the commentary to detail the following:

- IT systems: the type of IT systems required, distinguishing between new systems and modifications to existing systems, the functionality of the systems changes, the factors driving this requirement, and the basis / source of the cost estimation. Note that systems costs should only reflect the minimum necessary given the proposals described;

- Staff costs: the number of additional staff required (broken down by staff type where appropriate), the factors driving this staff requirement and the skills required, the assumed annual cost of the staff required (by staff type where appropriate), and the basis for the cost estimation;

- Other costs: the nature of any other costs incurred, the factors driving these costs and the basis for the cost estimation;

- The timing / phasing of the costs proposed i.e. do the one-off implementation costs occur in year one or over a period of time? Do the ongoing costs increase over a number of years before reaching a steady state, and if so, how?

- The key cost drivers (e.g. number of interfaces or degree of complexity) and breakdown of costs into key cost categories (e.g. customer service or overheads etc) wherever possible, explaining why such costs will be incurred;

- Sensitivity to the number of networks sold: we have asked that the costs associated with the sale of *four* distribution networks are estimated, however, the commentary should provide an indication of the extent to which these cost estimates would vary in the event that fewer distribution networks were sold;

- Where an important decision has yet to be reached which would have important implications for shipper costs, an estimation of the additional costs at risk should be provided, assuming that the 'worst case' decision is made (specific guidance is provided in certain cases within the assumptions paper);

- Interactions between sub-sections: detailing the interactions between areas the nature and extent of any common requirements / overlap, and any adjustments made to ensure accuracy of the cost totals; and where possible,

- High and low case scenarios: reflecting the potential for variation of the numbers presented (both up and down) and the associated probabilities of these alternative scenarios.

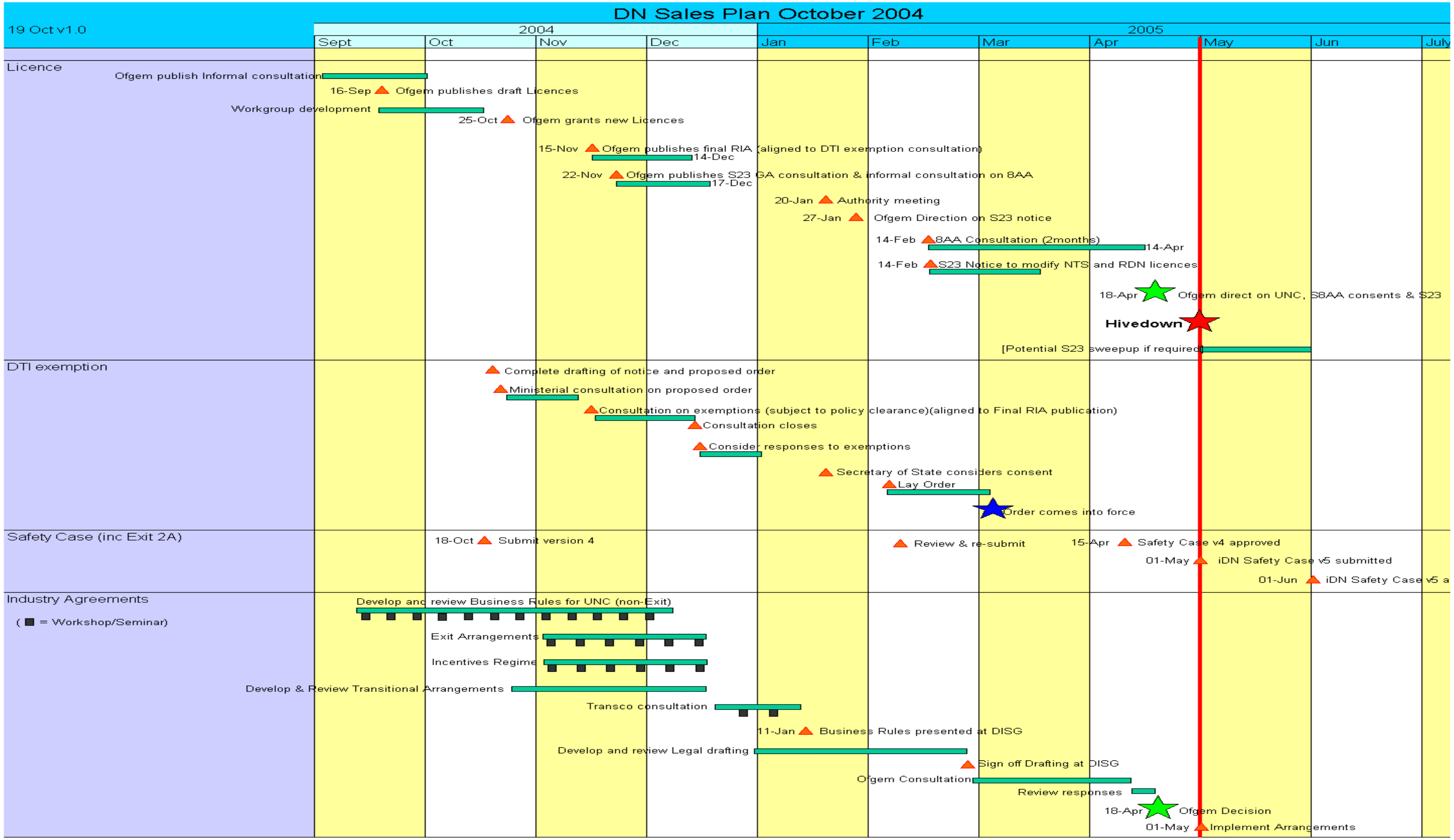
Queries

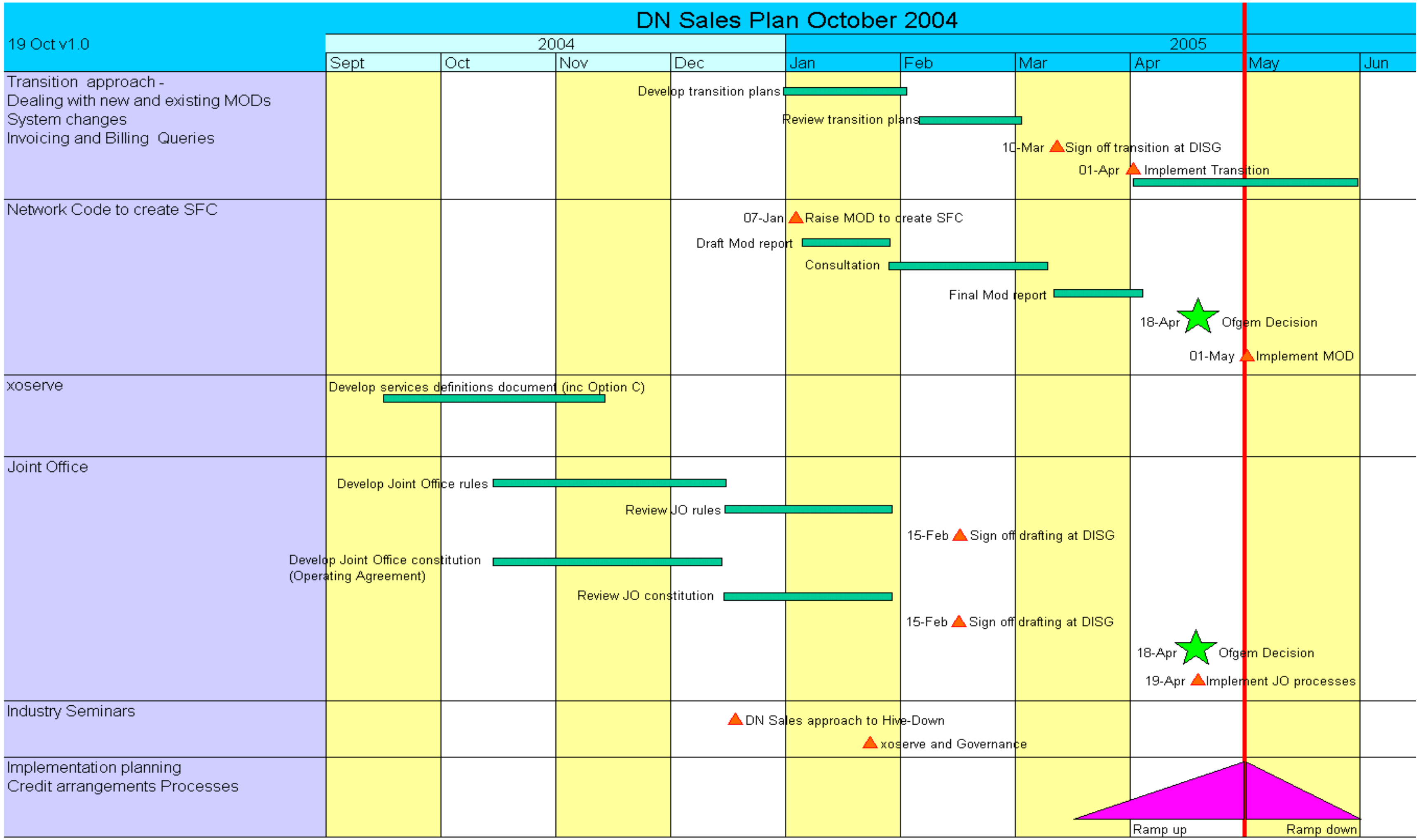
Should you have any queries regarding the content of this pro forma, please contact Hannah Cook on 0207 901 7444 (hannah.cook@ofgem.gov.uk).

Submission deadline

The information requested should be returned to Ofgem, by e-mail, by close of business on Friday 27 August 2004. Please e-mail responses to tracey.hunt@ofgem.gov.uk.

Appendix 14 NGT work plan for DN sales




DN Sales Plan October 2004
19 Oct v1.0
2004
2005
Sept
Oct
Nov
Dec
Jan
Feb
Mar
Apr
May
Jun
Transition approach -
Dealing with new and existing MODs
System changes
Invoicing and Billing Queries
Develop transition plans
Review transition plans
10-Mar Sign off transition at DISG
01-Apr Implement Transition
Network Code to create SFC
07-Jan Raise MOD to create SFC
Draft Mod report
Consultation
Final Mod report
18-Apr Ofgem Decision
01-May Implement MOD
xoserve
Develop services definitions document (inc Option C)
Joint Office
Develop Joint Office rules
Review JO rules
15-Feb Sign off drafting at DISG
Develop Joint Office constitution
(Operating Agreement)
Review JO constitution
15-Feb Sign off drafting at DISG
18-Apr Ofgem Decision
19-Apr Implement JO processes
Industry Seminars
DN Sales approach to Hive-Down
xoserve and Governance
Implementation planning
Credit arrangements Processes
Ramp up
Ramp down

Appendix 15 Issues relating to the potential legal separation of Transco's NTS and RDN businesses

15.1 This appendix provides a more detailed update on the Authority's current position in relation to legal separation of the NTS and RDNs.

15.2 For legal separation to occur, it would be necessary to move (or 'hive-down') part of Transco's business into a new legal entity. This could be achieved by either:

- hiving down Transco's NTS business into a new legal entity, leaving the RDN business in Transco's existing legal entity; or
- hiving down Transco's RDN business into a new legal entity with the NTS remaining in Transco's existing legal entity.

15.3 The Authority has considered both options in more detail since providing its "minded to" position to require legal separation. Following this further consideration, the Authority has decided that in the event that the proposed disposal of DNs proceeds, it would not be appropriate to require legal separation as both options have the potential to create risks and unintended consequences.

15.4 In this appendix we:

- explain the potential problems associated with legal separation which underpin the rationale for the Authority's revised decision; and
- describe a set of proposed licence conditions that could be imposed on NGT with the intention of emulating the affects of legal separation.

Potential problems with legal separation

15.5 As noted, legal separation of NGT's NTS and RDN businesses could potentially be achieved by either hiving down the NTS or hiving down the RDNs. Both approaches have potential problems which we discuss in the following subsections.

Hive-down of the NTS

15.6 Ofgem's July 2003 consultation document[65] and subsequent Next Steps document[66] both identified the resolution of arrangements for gas balancing as a gateway requirement associated with DN sales. A large majority of respondents to the July 2003 consultation document indicated that it is critical that the GB-wide gas trading arrangements are maintained in the event of DN sales. Ofgem agrees with this view.

15.7 Under the proposed mechanism for moving to a commercial framework under a sales scenario, the provisions of Transco's existing Network Code would, in the main, be re-established as an overarching Uniform Network Code (UNC). The existing Network Code itself would be modified into Transco plc's Short Form Code (SFC). This arrangement would be supplemented by new, individual SFCs for each network business. Each SFC would incorporate, by reference, the provisions of the UNC.

15.8 The arrangements would be given contractual effect through a framework agreement (between each relevant network and shippers) for each SFC. Transco plc's current framework agreement for the existing Network Code would remain in place in relation to its SFC. Were Transco to hive down its NTS business it would require a new SFC for NTS business and a new framework agreement. Therefore, the NTS's Network Code would not be Transco plc's Network Code

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[65] Ofgem, *National Grid Transco – Potential sale of distribution network businesses 77/03 A consultation document, July 2003*, Chapter 6.
[66] Ofgem, *National Grid Transco – Potential sale of distribution network businesses 170/03 Next Steps*, December 2003

but rather a new Network Code for a new legal entity. By contrast, were the RDN businesses to be hived down then the NTS Network Code, albeit a short form version, would be Transco plc's existing Network Code and the existing framework agreement would continue to operate as now.

15.9 The Authority considered that, were the NTS to be hived down from Transco plc's business there were two low probability but, were they to materialise, potentially highly significant risks to customers. These were that:

- the risk that existing third party contracts that reference Transco's Network Code might need to be adjusted. This risk, were it to materialise, would be potentially highly costly as current NBP contracts would need to be amended, or, in extremis, renegotiated. Furthermore, it could undermine confidence in the wholesale gas market and trading at the NBP with potentially very significant impacts upon customers; and

- the risk that the wholesale gas market fragments into a number of individual Network Codes. This might arise as a result of requiring shippers to sign a new framework agreement for the NTS as well as a proportion of the DNs. Again, this could have a very serious impact upon wholesale competition with consequential costs to customers.

15.10 Therefore, although small risks, given their potential materiality, the Authority considered it would not be appropriate for Transco to hive down the NTS into a new entity.

Hive-down of the RDNs

15.11 The Authority also considered the possibility of requiring Transco to hive-down its RDN businesses from Transco plc to a new Transco subsidiary company.

15.12 Transco has suggested that the hive-down of the RDNs would cause Transco to incur disproportionately high costs. These would result from:

- the need to identify and transfer all of the relevant RDN assets to a separate legal entity; and

- restructuring of Transco plc debt. As the RDN's comprise of a significantly larger proportion of Transco plc's business than the NTS, an effect of requiring the RDNs to be hived out of Transco plc would be to trigger bond holder covenants of existing Transco debt. This would impose significant debt restructuring costs on Transco.

15.13 Overall, the Authority considered that the potential costs associated with requiring the RDNs to be hived out of Transco plc to be disproportionate to the potential benefits that legal separation would bring for customers. For this reason, it decided that it would not require the RDN businesses to be hived down.

Licence conditions

15.14 Given these potential problems with the hive-down of either the NTS or the RDNs, the Authority has considered an alternative in which Transco would not be required to separate legally its NTS and RDN businesses, but that would deliver many of the benefits of legal separation. For instance, Ofgem could insert a Special Condition in Transco's NTS licence that requires Transco:

- to establish a set of arrangements between the NTS and the RDNs which are not unduly different from the contractual arrangements entered into with IDNs; and

- to obtain an undertaking from its parent company to apply the arrangements between the NTS and RDNs on the same basis as contracts entered into with non-affiliated businesses.

15.15 It is proposed that such mechanisms would permit Ofgem to take enforcement action in the event that Transco NTS gave preferential treatment to its RDN business. These arrangements would reflect the arrangements in place within British Gas prior to the demerger.

15.16 Ofgem could also introduce licence conditions that seek to recreate the benefits of legal separation in terms of corporate governance. For instance, in the water industry, Ofwat has recently required water companies to:

- conduct their affairs as though the regulated business were substantially their only business;
- conduct their affairs as though they were stand-alone public limited companies listed on the London Stock Exchange; and
- have at least three non-executive directors who are independent of any affiliate of the licensee.[67]

15.17 Finally, Ofgem could require Transco to submit separate regulatory accounts for its NTS and (each individual) RDN business that are in the same format as statutory accounts.

15.18 This approach could lead to a greater level of regulatory complexity than legal separation. However, given the potential costs associated with legal separation, Ofgem considers that it would be a proportionate response to the risks associated with undue discrimination. Ofgem's proposals for licence conditions seeking to emulate the effect of legal separation will be developed in more detail through the DISG and the licensing consultation process.

15.19 For the avoidance of doubt, the Authority intends to retain the requirements for structural separation.

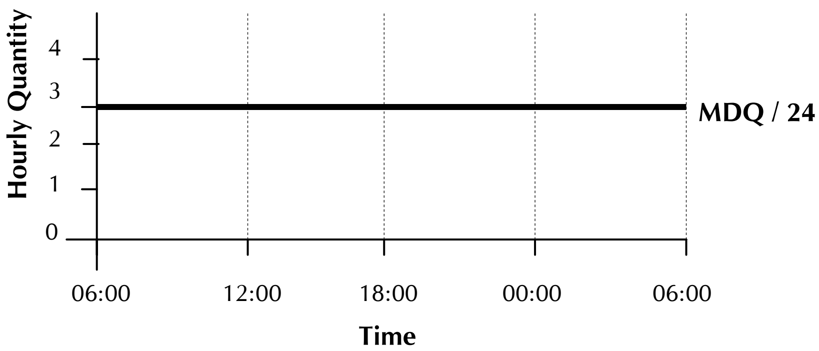
[67] See *South East Water Ltd, Instrument of Appointment as a water undertaker under the Water Act 1989*, as amended in June 2004.

Appendix 16 NTS offtake flexibility

Definition of NTS offtake flexibility

16.1 Before a model for NTS offtake flexibility can be described, it is important to understand in more detail the rights that will be provided by the NTS to the holder of basic NTS exit capacity under the proposed offtake arrangements. This is illustrated by way of a simple example in Figure A.8 below.

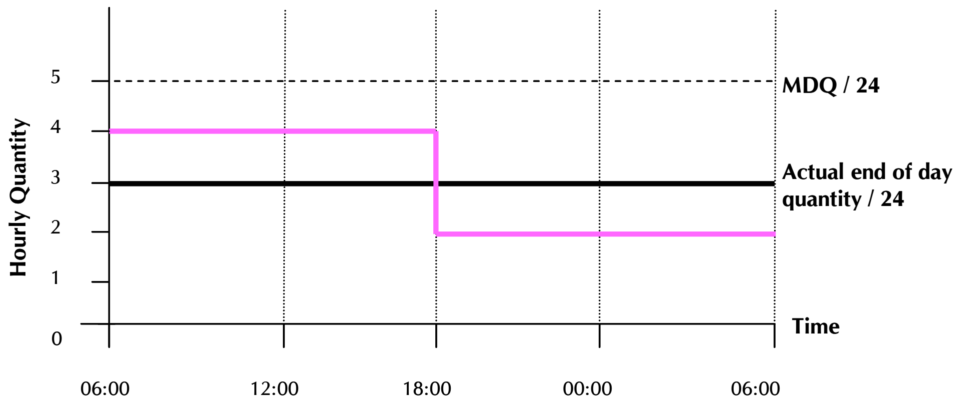
Figure A.8 NTS exit capacity product



16.2 In this example, assume that the NTS connectee has purchased 72 units of NTS exit capacity for a given day; in other words, the Maximum Daily Quantity (MDQ) of offtake is 72 units. Importantly, by purchasing these rights, the holder is allowed to offtake at a **flat hourly rate of a maximum of MDQ/24**. In this example, the NTS connectee has the right to offtake gas at a maximum hourly rate of 3 units per hour (for the entire 24 hours of the day).

16.3 In practice, NTS connectees typically desire to offtake gas at varying rates through the day. An example of an offtake profile in which this is the case is shown in Figure A.9.

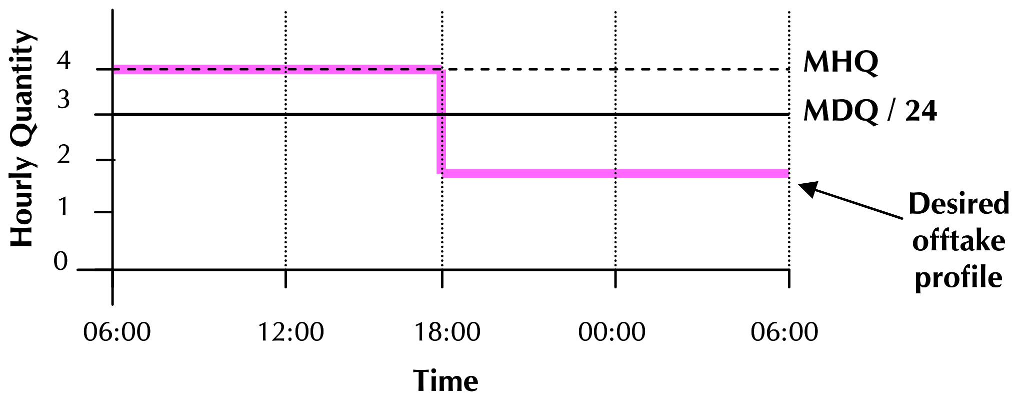
Figure A.9 NTS offtake flexibility



16.4 In this diagram, for a given day, a connectee has purchased sufficient capacity to allow a flat offtake of 5 units per hour (i.e. daily MDQ = 120 units). Despite this, the connectee chooses to only offtake 72 units of gas during the day (i.e. at an average offtake rate of 3 units per hour). However, the connectee wants to use flexibility during the day, offtaking gas at a rate of 4 units per hour for the first part of the day and at 2 units per day for the latter half of the day.

16.5 A further example of a (potential) use of flexibility by an NTS connectee is presented in Figure A.10 below:

Figure A.10 NTS offtake flexibility above MDQ



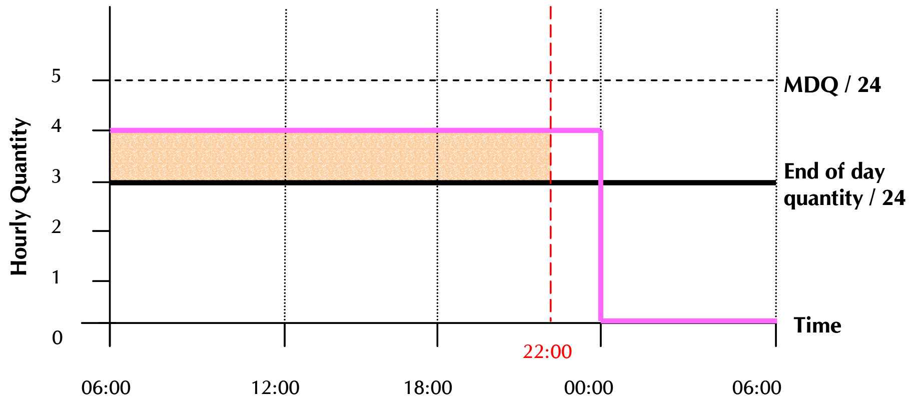
16.6 In Figure A.10, the desired offtake profile of the NTS connectee (depicted by the thick line), shows that the NTS connectee wants to offtake at a rate of 4 units per hour for the first half of the day, followed by a rate of 2 units per hour for the second half of the day. In total, therefore, the MDQ for the day is 72 units (as in the previous example), yet the Maximum Hourly Quantity (MHQ) required by the connectee is 4 units per hour, rather than the 3 units per hour that is permitted through the holding of the basic NTS exit capacity[68].

16.7 Hence, a requirement for flexibility can arise both above the purchased level of capacity (as outlined in Figure A.10) and at lower levels of offtake (Figure A.9).

Flexibility in the proposed offtake arrangements

16.8 Based upon this fundamental understanding of what constitutes flexibility of offtake, NGT has proposed defining a flexibility product as illustrated in Figure A.11 below:

Figure A.11 Deviation from flat profile



16.9 Under NGT's proposed definition, connectees that offtake gas from the NTS with anything other than a flat offtake profile throughout the day (i.e. higher than the "end of day quantity"/24 rate) use NTS offtake flexibility (irrespective of whether they breach their MDQ/24 hourly offtake threshold) [69]. NTS connectees are then required to purchase a level of NTS offtake flexibility equal to their net impact on the system at 10 p.m. (i.e. the impact of their usage of flexibility on the system at the time at which the NTS is typically under most stress).

[68] At present, NTS direct connected customers would not be able to offtake according to this profile (as MHQ is constrained to equal MDQ/24). In the above example, were it to desire to do so, it would need to purchase MDQ of 96 units rather than 72.
[69] Note that NGT have proposed defining a "tolerance band", within which small variations in offtake rates are allowed without the requirement to purchase flexibility rights.

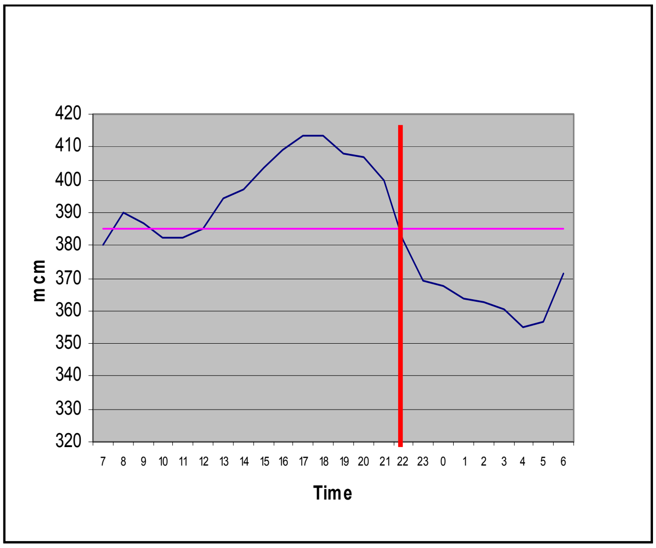
16.10 In Figure A.11, therefore, 16 units of flexibility would be required (i.e. 1 unit of flexibility used for 16 hours up to 22:00).

16.11 The product definition therefore has two key defining characteristics.

- **Defined independently of MDQ**. The product is not linked to the purchased level of MDQ. Instead, flexibility is defined with reference to actual end of day offtake.

- **Flexibility product only required for the time period 06:00 to 22:00**. This is because the time at which connectees use flexibility has design implications for the NTS. Specifically, without knowing when flexibility is going to be used during the day, the NTS would be unable to determine the maximum amount of offtake capacity that would needs to be provided during the gas day. This point is illustrated in Figure A.12, below.

Figure A.12 NTS demand (15 January 2004)[70]



16.12 This diagram shows that, taking the NTS as a whole, rates of offtake are typically higher than average in the period from 06:00 hours to around 22:00 hours, resulting mainly from the profile of NDM load within the DNs. Critically, it is

[70] Data as presented by Transco to the DISG meeting on 7 September 2004.

the volumes provided in this period that the NTS needs to understand for investment planning purposes. For this reason, Transco considers that the NTS offtake flexibility product needs to indicate the volume of flexibility that will be used by connectees over the "peak" period of flexibility usage.